A New Generation of Energy

December 21, 2006

Ms. Lezael Rorie
ICF International
9300 Lee Highway
Fairfax, VA 22031

Mr. Jonathan Winer
La Capra Associates
21 Winthrop Square
Boston, MA 02110

Re: DP&L Company Request for Proposals for New Generation

Dear Ms. Rorie and Mr. Winer:

Conectiv Energy is pleased to provide Delmarva Power & Light Company ("DPL"), IFC International, and La Capra Associates the following response ("Proposal") to DPL's Request for Proposal dated October 30, 2006. Conectiv Energy has structured and priced this Proposal based on our successful record of constructing and commissioning similar facilities, our record of safe and dependable unit operation, the unique suitability of the proposed project site, and just as important, our extensive experience in energy trading. As a result, we are confident that our Proposal will be the lowest cost option for DPL's solicitation for energy and capacity, provide unique operating and cycling capability not offered by the competitors, offer the earliest commercial operation date and enhance reliability in the DPL service territory. Furthermore, Conectiv is convinced that this project includes the highest guaranteed availability and is the only technology with actual long term historical operating data.

Conectiv Energy is offering two pricing options in this Proposal. Both utilize a nominal 180 MW Unit (the "Project") that utilizes efficient state-of-the-art combined cycle technology. The Project will be located at the existing Hay Road Power Complex in New Castle County, Delaware. The Hay Road Complex, currently consisting of Hay Road Units 1-8, is owned and operated by Conectiv Delmarva Generation, Inc. ("CDG"), a wholly owned subsidiary of Conectiv Energy Holding Company ("CEH"). The Project will be constructed, owned and operated by either CDG or another of CEH's generation owning subsidiaries.

Electric interconnection from the Project to the PJM grid will be at the adjacent Hay Road 230 KV Red Lion line and will not require the acquisition of additional rights-of-way.

Natural gas will be the primary fuel, and low sulfur light petroleum product will serve as secondary fuel. The dual fuel capability will ensure that all operating commitments are met. Natural Gas will be delivered via an existing lateral sourced to three (3) interstate pipeline companies. Liquid fuel oil will be delivered by barge to the existing Edge Moor Power Plant barge unloading facility, and then pumped to the site via an existing pipeline.

From an environmental and land use perspective, the Project is unique because it is a brownfield site located directly adjacent to existing electric generating facilities, is zoned Heavy Industrial, and is surrounded by compatible industrial land uses. The existing infrastructure will allow for cooling water needs to be satisfied without additional offsite facilities and moreover, the site lacks potentially sensitive resources such as wetlands, protected species or habitats, or cultural resources.

Conectiv Energy has the proven engineering, permitting, and construction experience to deliver the Project on time and within budget. Conectiv Energy's project teams are uniquely qualified as they have successfully engineered, constructed, and commissioned more than 1,650 MW of combined cycle generation in the last five years. Conectiv Energy continues to own and operate more than 3,600 MW of generating capacity in the base, mid-merit, and peak load segments. Our operating teams have the experience and ability to meet unit commitments, and do so daily.

All of CEH's generation owning subsidiaries have entered into tolling agreements with another of CEH's subsidiaries, Conectiv Energy Supply, Inc. ("CESI"), under which CESI acquires all of the fuel used in the generation facilities. Conectiv Energy intends for CESI to enter into a similar tolling agreement with the CEH subsidiary that will own and operate the Project. CESI has in place, and will continue to maintain, the proven professional relationships with the necessary brokers, marketers, and financial entities required to meet all of the fuel needs for this Project. CESI professionals have the expertise and internal processes in place to manage the physical and financial requirements to ensure a reliable fuel supply for the Project. They have successfully utilized this expertise to manage the fuel requirements of the remainder of the Conectiv Energy fleet of generation facilities for more than ten years.

Under the terms of its tolling agreement with the CEH subsidiary that owns the Project, CESI will have the right to all of the Products produced at the Project. Therefore, CESI will be the Conectiv Energy legal entity that will execute the PPA and sell the Products to DPL.

Conectiv Energy is offering DPL two alternatives within this Proposal. The only differences between the two relate to pricing of the Products sold to DPL (as described in Form R of the Proposal) and the authority to schedule and dispatch the Project. **Please note that Conectiv Energy respectfully requests that its proposed pricing terms contained on Form R be maintained as confidential.**

The first alternative (the “Base Offer”) is a unit contingent sale under which (i) CESI will sell to DPL all of the Products produced at the Project and (ii) DPL will have the right to direct the dispatch of the Project. The Base Offer includes both Capacity and Energy charges. The charges for Energy produced while the Project is in the base operating mode (up to 152 MW) during PJM on-peak hours are indexed to coal indices and the GDP implicit price deflator. Conectiv Energy believes that this should provide the price stability sought in the RFP. The charges for Energy produced during PJM off-peak hours and while the Project is operating in excess of base operating mode (up to 177 MW) are structured so that DPL can elect to purchase Energy under the PPA only when economically beneficial.

The second alternative (the “Alternate Offer”) is an asset backed capacity agreement with firm energy under which (i) CESI will sell to DPL the capacity associated with the Project (177 MW); (ii) CESI will transfer to DPL the revenues received from PJM for sale of the Ancillary Services associated with the Project; and (iii) CESI will to DPL sell a quantity of Energy that is equal to the quantity that would be produced at the Project if it were operating subject to DPL’s dispatch. Under the Alternative Offer, however, CESI retains control over the dispatch of the Project and CESI decides upon the source of the Energy that it will deliver to DPL.

We believe that the Alternate Offer provides the lowest overall cost to DPL and its customers. By retaining the ability to optimize the scheduling and dispatch of the Project Conectiv Energy has been able to significantly reduce the capacity charge while retaining the same predictable on-peak energy price contained in the Base Offer.

Conectiv Energy is proposing a term, for both alternatives offers, of 10 years with an option available in years five through eight to extend the PPA for an additional five year term.

Finally, although not specifically included in this Proposal Conectiv Energy does have the infrastructure and facilities to increase this Project size to nominally 360 MW and to configure the PPA accordingly with the same pricing proposals contained herein.

Thank you for the opportunity to participate in the Request for Proposal for the Power Generation Project. We look forward to participating in the evaluation process and are poised to discuss our unique proposal and viable alternative with you. Prior to the final contract formation, review of the negotiated contract terms, conditions, and obligations will require final approval by the PHI Board of Directors.

Please contact Mr. Richard Purcell at (302) 451-5512 or alternatively Rich.Purcell@ Conectiv.com with any clarifications or comments regarding the Proposal.

Sincerely,

Arturo F. Agra
Vice-President
Conectiv Energy

cc: Albert F. Kirby- Conectiv Energy
David M. Velazquez – Conectiv Energy

Proposal Presented to:

ICF International *La Capra Associates*

In Response to Delmarva Power Request for Proposal for New Generation Resources

Submitted by:
Conectiv Energy Supply, Inc.
December 21st, 2006

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I. TECHNICAL FACILITY DESCRIPTION

The proposed Project, nominally rated at 180 MW, utilizes Combined Cycle technology in a 1 X 1 configuration which includes a single combustion turbine plus a single steam turbine generator. The units will be installed at the Hay Road Power Complex in New Castle County, Delaware as an expansion project. Unit designation will be Unit No. 9 (Combustion Turbine) and Unit No. 10 (Steam Turbine). BOP equipment will be designated as required.

The Combustion Turbine will be a Siemens-Westinghouse V84.2. The unit will have dual fuel capability with Natural gas as the primary fuel, and low sulfur light petroleum product as the secondary fuel. Natural gas will be delivered via an existing lateral sourced to three (3) interstate pipe line companies. Liquid fuel will be delivered by barge to the existing Edge Moor Power Plant barge unloading facility, and then pumped and stored at the site using an existing pipe line and 250,000 barrel storage tank.

The exhaust from the combustion turbine would be used to produce steam in a two pressure (high pressure and low pressure) heat recover steam generator (HRSG) for the steam turbine. The HRSG will employ an SCR utilizing anhydrous ammonia for NOx reduction in the combustion turbine exhaust. Anhydrous ammonia will be supplied via an existing storage tank located on-site. No CO catalyst will be required due to the unique silo combustors installed on the Combustion Turbines.

High and Low Pressure steam will be piped to an industrial designed Condensing Steam Turbine Generator containing high and low pressure turbine sections. Steam exhausted from the high pressure section will mix with the low pressure steam from the HRSG and be re-injected to the turbine. All steam used in the steam turbine will be condensed and reused in the process. Demineralized water used in the steam cycle will be processed from an existing water plant on site. Additional storage and system capacities will be upgraded as required to meet the needs of the new project.

Cooling water needs for the project will be achieved via the installation of a new mechanical draft cooling tower. This new tower will be used to remove the heat rejected from the circulating water from the condenser and other miscellaneous mechanical heat loads in the expanded facility. Makeup water (river water) for cooling will be provided from existing infrastructure piped from the outfall of Edge Moor Power Plant. Blowdown will be discharge in the existing Hay Road Unit 8 cooling tower blowdown line.

The Combustion and Steam Turbine Generators (2 total) will each be connected to a dedicated generator step up transformer to increase the Generator voltages from 13.8 kV to 230 kV. The output side of each step-up transformer will be electrically interconnected to high side circuit breakers then to the existing 230kV transmission line servicing Hay Road Units 5-8. This transmission line is interconnected to the Red Lion substation. A station service transformer and unit auxiliary transformers will be installed as required to satisfy medium and low pressure voltage applications.

Balance of plant equipment, back up power supplies, fire protection, and other critical ancillary systems will be installed to ensure the safe and reliable operating conditions required to meet the requirements of the RFQ.

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	a. Form A

Form A - Notice of Intent to Bid

Date: 22-Nov-06

Our organization intends to submit a proposal in response to the Delmarva Power & Light Request for Proposals for Generation Capacity and Power Purchase Agreement:

Contact Name: Richard Purcell

Name of Firm: Conectiv Energy

Address: 500 N. Wakefield Drive
Newark, DE 19702

Phone: 302-451-5512

e-mail: rich.purcell@conectiv.com

Alternate Contact Name: Krish Raju

Address: Conectiv Energy
500 N. Wakefield Drive
Newark, DE 19702

Phone: 302-451-5398

e-mail: krish.raju@conectiv.com

Project Description:

(include technology type, incremental facility capacity (MW), expected capacity factor and interconnection point (PJM bus #))

Conectiv proposes two alternate Projects. Both Projects shall utilize combined cycle technology. The base Project will be a 2CTx1ST configuration nominally rated at 360MW. The expected capacity factor will be 40% nominally. 240MW will be interconnected on PJM bus # 52463 (Red Lion 500 kV) and 120 MW will be connected on PJM bus # 1047974 (Edge Moor 230 kV). The alternate will be a 1CTx1ST configuration nominally rated at 180MW. The expected capacity factor will be 40% nominally. All capacity will be interconnected on PJM bus # 52463 (Red Lion 500 kV).

Signature: Richard D. Purcell

Please return via FAX, U.S. Mail, or email no later than Wednesday November 22, 2006 to

Lezael Rorie
ICF International
9300 Lee Highway
Fairfax, VA 22031
FAX: (703) 934-3968
E-Mail: dpl_rfp@icfi.com

and

Barry J. Sheingold
New Energy Opportunities
125 Powers Road
Sudbury, MA 01776
FAX; (978) 440-7654
E-Mail: bjs@newenergyopps.com

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Form B - Certification Form

The bidder hereby certifies that all of the statements and representations made in this proposal are true to the best of the bidder's knowledge and belief, and agrees to be bound by the representations, terms, and conditions contained in the RFP. The bidder accepts the ***Power Purchase Agreement*** included in the RFP, except as specifically noted in writing. This proposal is firm and will remain in effect for at least ***210 days*** after the proposal due date.

Submitted by: Conectiv Energy Supply, Inc.
(exact legal name of firm)

Bidder: ______________________
(if different than above)

Signature of an officer of bidder: ______________________

Print or type name of officer: Arturo F. Agra

Title: Vice President

Date Signed: December 20, 2006

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	c. Form C

Form C - Bid Summary

Generation Facility

1) Project / Facility Name: Hay Road Units 9 & 10 / Hay Road Power Complex

2) Project Location (city, county): Wilmington, New Castle County

3) Project Location (latitude, longitude): 39.75° N Latitude / 75.50° W Longitude

4) Bidder Contact:

Name:	Richard Purcell
Company:	Conectiv Energy
Address:	500 N. Wakefield Drive Newark, DE 19702
Phone / Fax:	(302) 451-5512 / (302) 451-5267
email:	Rich.Purcell@Conectiv.com

5) Generation Technology - general description of the proposed generation technology (e.g. pulverized coal, IGCC, combined cycle) including environmental control equipment. If retrofit or repowering, describe the proposed modification in detail.

Dual Fuel Combined Cycle Power facility constructed in 1 x 1 configuration equipped with S-W V84.2 Technology to allow for up to 2x's per day cycling, 20 minute energy delivery, 2 hour full load capability (Warm). Plant configured with SCR system for NOx control, no CO control required due to burner selection.

6) Facility Fuel Type and Transportation - (describe primary and secondary fuels, if applicable)

Primary Fuel:	Natural Gas	Secondary Fuel:	Low Sulfur Light Petrol Prod
Transportation:	Pipe Line	Transportation:	Barge

7) Transmission Interconnection

Point of Interconnection (PJM Bus #):	180 MW - CT + STG on HR Red Lion 230 KV (8804)
Point of Interconnection (PJM Bus #):	
Interconnection Voltage (kV):	230 KV
Delivery Point as per PPA	HR / Red Lion 230 KV (DP&L Bus No. 23020)
Delivery Point Voltage	230 KV

8) Capacity Rating

Facility Net Design @ ISO Conditions (MW)	176 MW
Facility Summer (MW) at site conditions (92 degrees F)	177 MW
Facility Winter (MW) at site conditions (30 degrees F)	175 MW
PPA contract UCAP (MW)	177 MW
PPA Summer Dependable Capacity (MW)	177 MW
Uncommitted Capacity (MW)	0 MW

9) Proposed Commercial Operation Date (COD):

(Up to two commercial operation date options can be offered under one bid evaluation fee.)

Base COD: June 2011 [Contract Award On or Before 5/2007] Optional COD:

10) Proposed Contract Duration: 10 years - June 1, 2011 - May 31, 2021 [May 2007 Contract Award Req]

(Either the expiration date to an anniversary of COD or list the desired date)

11) PPA Contract Type - describe price (e.g. fixed price index based price, capped or collared price) and percentage of output offered. If PPA is for renewable capacity indicate if renewable energy credits are included in the bid and if so how many.

All output from the project (100%) is dedicated to the PPA. The Capacity price (expressed in $/kw-month) is based on a fixed price during the term. Energy price (expressed in $/MWH) is variable and is escalated using a Platts OTC Coal Broker-Based "NYMEX look-alike - 12,000 Btu/lb. -1%" index (50%) and GDP Implicit Price deflator (50%) for the term of the contract.

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d. Form D - Complete with Attachments

Form D - Generation Facility Technical Description

This Form requests information regarding the Generation Facility for purpose of evaluating the overall impact of the Facility on the system and on the Delmarva Residual Standard Offer Service customers. If the Proposal consists of more than one generating unit with different operating characteristics, the Bidder should provide applicable information for each unit. If data is excluded, the evaluators may at their option elect to utilize generic characteristics consistent with the proposed capacity type or, if the information should be known by the Bidder, reject the bid as non-responsive. Some information requested may not be known by the Bidder at this time; Bidder is expected to respond to each question to the extent such information is known or can be reasonably obtained.

1) Project / Facility Name: Hay Road Units 9 & 10

2) Generation Technology:

Describe the number and type of proposed generator units:
Proposed project will consist of one (1) Siemens V84.2 combustion turbine, one (1) HRSG, and one (1) condensing steam turbine operated in combined cycle.

Configuration of generation equipment, i.e., CTs, HRSGs, steam turbines, etc.:
1CT x 1HRSG x 1ST

Generation equipment model numbers, vendors, manufacturers, etc.:
CT: Siemens V84.2 CT with Siemens TLRI 100/30-36 Generator
STG: Siemens SST-900 Steam Turbine with Siemens TLRI 86/26-36 Generator*
*PRELIMINARY - RIGHT RESERVED TO SUBSTITUTE STG WITH EQUIVALENT TECHNOLOGY UPON AWARD.

3) Expected PJM Capacity Rating (kW):

(indicate conditions for temperature, altitude, and power factor for which the data is supplied where applicable)

UCAP	177 MW
Net Summer Dependable	177 MW (16 FT ASL, 92F, 0.98 PF)
Net Winter Dependable	175 MW (16 FT ASL, 30F, 0.98 PF)
Maximum operating level	177 MW (16 FT ASL, 92F, 0.98 PF)
Minimum operating level	120 MW (16 FT ASL, 59F, 0.98 PF)
Most efficient operating level	151 MW (16 FT ASL, 59F, 0.98 PF)

4) Expected Annual Forced Outage Rate (%): 2.5%
(This rate should include only forced outages and unplanned maintenance, not planned maintenance.)

5) Expected Average Annual Maintenance Requirements (days/year): 28 Days/Year

On-peak Months (May, June, July, August, September): None
Off-peak Months: 4 Weeks (2 weeks ea Spring/Fall)

6) For non-intermittent facilities, state the target equivalent availability factor and the projected capacity factor. For intermittent resources, state the projected capacity factor. Describe performance guarantees for facility operation.

Estimated EAF = 90%
Estimated CF = 48%

Performance guarantees to be provided for Availability, Energy, and Capacity

Form D - Generation Facility Technical Description

7) Describe any circumstances under which the Facility output will have to be curtailed on a predictable basis such as soot blowing and/or deslagging, maintenance, steam host operation, etc.)

None anticipated on a predictable basis.

8) Heat Rate

Average and incremental heat rates for the Facility, higher heating value for the primary fuel specified or anticipated fuel blend.

	Average Heat Rate (BTU/kWh)**	Incremental Heat Rate (BTU/kWh)
Minimum Operating Level **(68% Load)**	7,988	5,560
50% of net capability	Not Applicable	Not Applicable
75% of net capability	Data Not Available	Data Not Available
86% of net capability	7,637	6,282
100% of net capability	7,691	8,023

* **Higher Heating Value for NG Used is 23,000 btu/lb**

** **Heat Rates at Iso conditions. Actual conditions will vary as a function of ambient conditions and operating mode**

9) Is proposed plant AGC controllable? Yes ____ No X

a) Low AGC Point (lowest output than can be achieved while the unit is on AGC)
Not Applicable

b) High AGC Point (highest output than can be achieved while the unit is on AGC)
Not Applicable

10) Minimum on-line time Eight (8) Hours
(minimum time between the generator breaker closing and re-opening)

11) Minimum downtime Four (4) Hours
(minimum time the generator needs to be off-line prior to restarting)

12) Start time - (unit has been off-line for six hours) Twenty (20) Minutes
(the time it takes for the unit to start, close breaker and reach minimum load

13) Start time - (unit has been off-line for eight hours) Twenty (20) Minutes
(the time it takes for the unit to start, close breaker and reach minimum load

14) Start time - (unit has been off-line for 12 hours) Twenty (20) Minutes
(the time it takes for the unit to start, close breaker and reach minimum load

15) Start time - (unit has been off-line for 3 days) Twenty (20) Minutes

16) AGC Ramp Rate Not Applicable
(rate at which the unit responds to frequency changes while on control (MW/minute)

Form D - Generation Facility Technical Description

17) Normal Ramp Rate Ten (10) MW/min. - after initial start and base load operation
(rate at which the unit can increase output while on manual control (MW/minute)

18) Emergency Ramp Rate Ten (10) MW/min. - after initial start and base load operation
(rate at which the unit can increase output only for emergency situations MW/minute)

19) Ten-minute Start Capability Yes ______ No X
If yes, achievable unit loading 10 minutes after synchronizing to system Not Applicable

20) Describe the performance history of major components such as turbines, boilers, generators, solar cells, modules or tracking equipment, etc.
The V84.2 has been used reliably over the past sixteen (16) years, with twelve (12) units currently in Conectiv Energy's fleet.
Similar combined cycle reliability can be demonstrated in the success of Conectiv Energy's 3x1 power block configurations, with over 2000 MWs in operation at Hay Road in Wilmington, DE and Bethlehem, PA.

21) Describe any unique benefits or value associated with the proposed technology as compared to other technologies in its class.
Combined Cycle technology provides Heat Rates lower than conventional power plant technologies. As compared to other CC units, the V84.2 allows for faster starts, provides up to 2 daily starts, has turn down capability, and utilizes lower combustion temperatures that allows for lower maintenance costs and quicker turn-arounds. Peak capacity segments are also available making the unit reliable, flexible, and efficient.

22) Provide any other relevant information about the proposed technology.
The proposed technology is mature and reliable. Conectiv Energy has multiple years experience (14 total) operating and maintaining the V84.2 in combined cycle operation.

23) Provide reactive power capability curve.
See Attachments Included in this section

24) Provide maximum reactive power productive and absortive capability.
CT: 17 MVARs Absorptive (-), 20 MVARs Productive (+)
ST: TBD

Form D - Generation Facility Technical Description

25) Technical Data:

Generator MVA Base	CT: 144 (ea.) ST: 70	
Generator Nominal Power factor	0.85	
Generator Terminal Voltage	13.8 kV	
Direct Axis Synchronous Reactance Xd	CT: 172% ST: 183%	**NOTE 1**
Direct Axis Transient Reactance X'd	CT:19.6% ST: 20.8%	**NOTE 1**
Direct Axis Sub-Transient Reactance X"d	CT:13.2% ST: 13.2%	**NOTE 1**
Generator Step-up Transformer MVA Base	CT: 83.4 ST: 41.7	
Generator Step-up Transformer Impedance (R+jX on transformer MVA Base)	CT: 7.5% ST: 7.5%	
Generator Step-up Transformer Rating (MVA)	CT: 144 ST: 72	
Generator Step-up Transformer Low-side Voltage (kV)	13.8 kV	
Generator Step-up Transformer High-side Voltage kV)	230 kV	
Generator Step-up Transformer Number of taps and step size	4 / 2.5%	

NOTES:

1. ALL VALUES LISTED ARE SATURATED

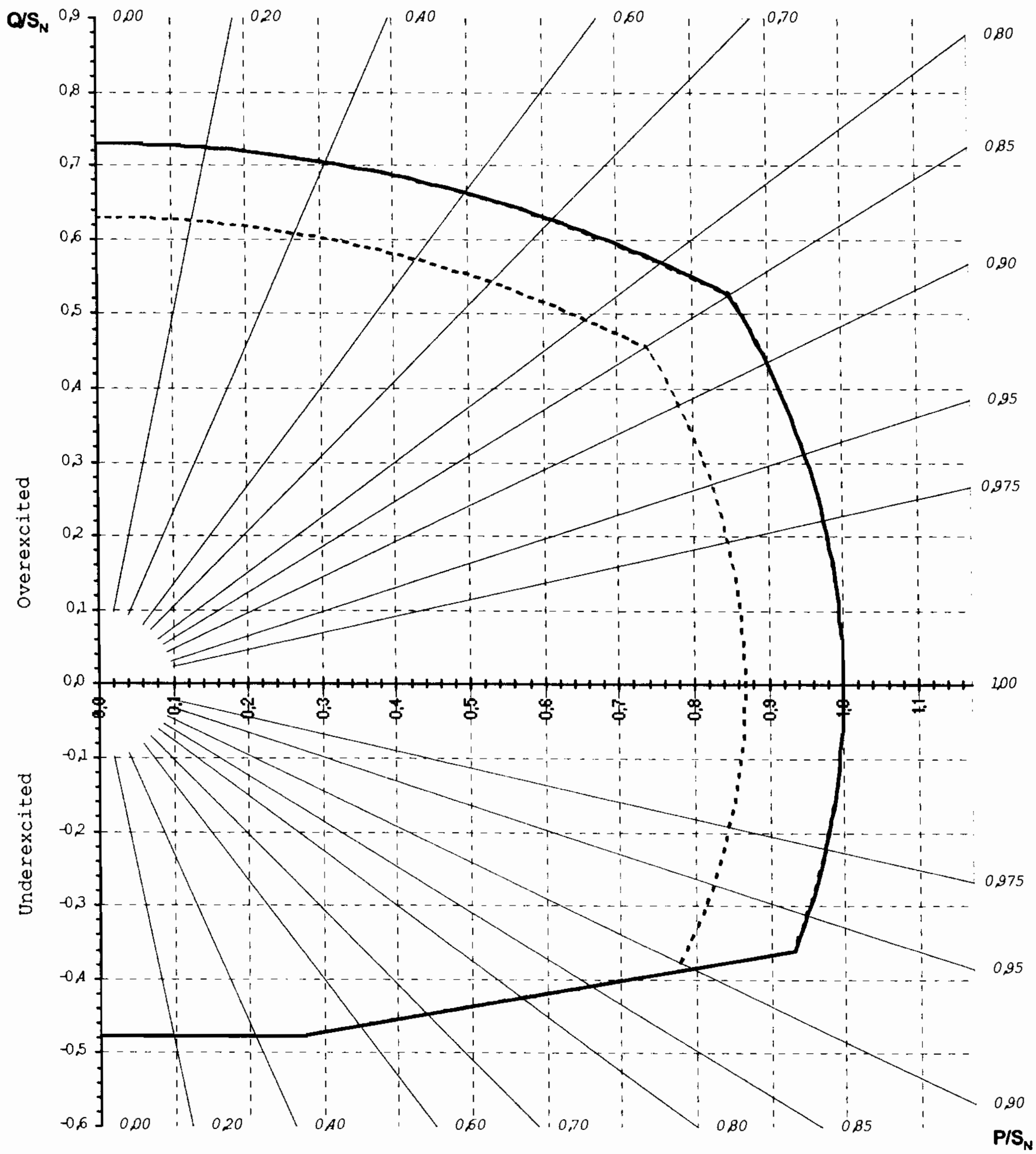
2. Conectiv Energy RESERVES THE RIGHT TO ALTER STEAM TURBINE, GENERATOR, AND GSU DATA BASED ON FINAL EQUIPMENT SELECTION

Turbogenerator
Description

Reactive Capability Curve

Generator - Type: TLRI 100/30-36

Load Point			Rated	A	B
Generator Output	S_N	=	144.000 MVA	144.000 MVA	125.000 MVA
Armature Voltage	U_N	=	13.800 kV	13.800 kV	13.800 kV
Armature Current	I_N	=	6.025 kA	6.025 kA	5.230 kA
Frequency	F_N	=	60 Hz	60 Hz	60 Hz
Power Factor	P.F.	=	0.850	0.850	0.850
Cold Gas Temperature	T_{Cold}	=	86 °F (30 °C)	57 °F (14 °C)	126 °F (52 °C)

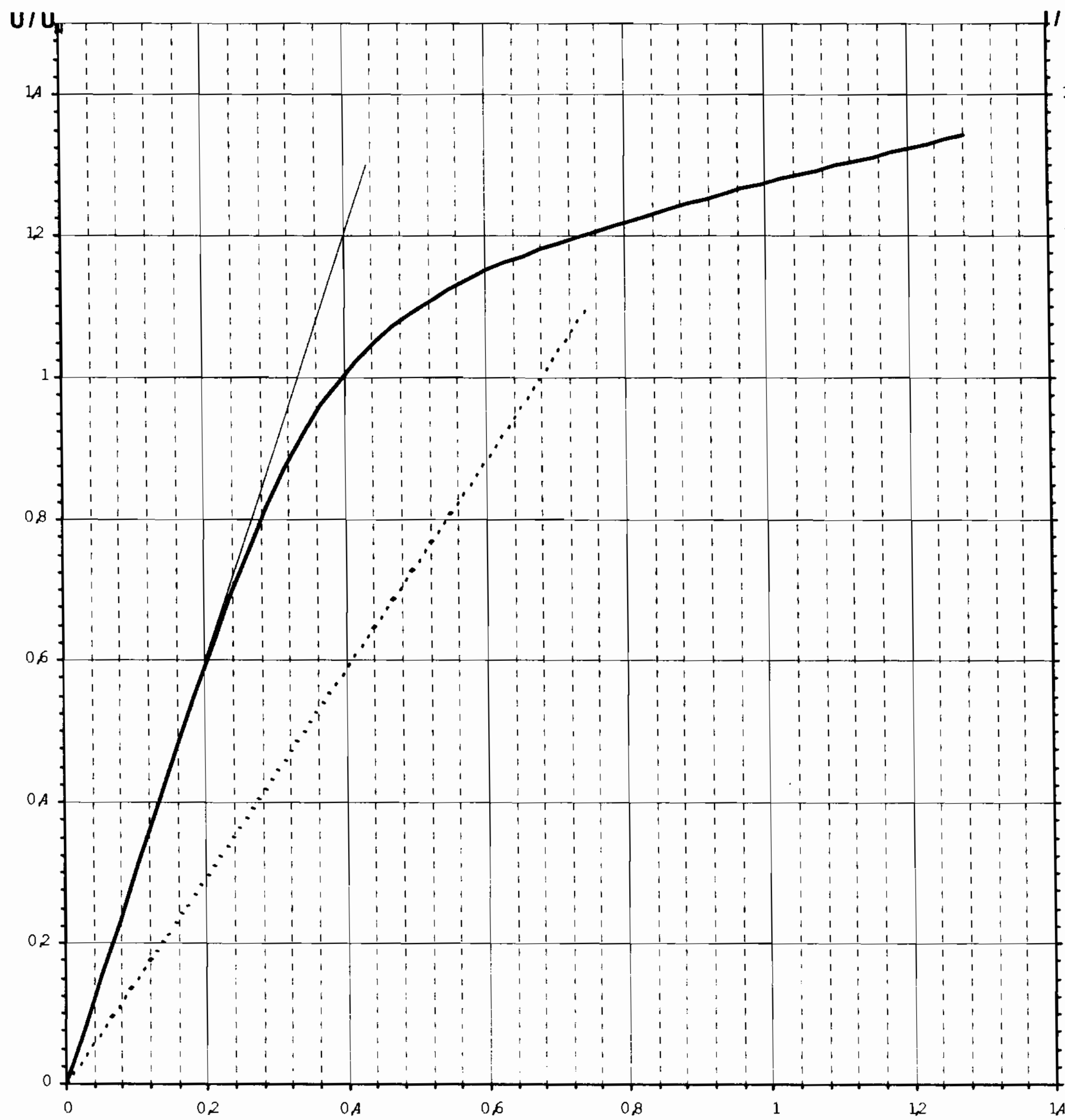


GENERATOR TYPE: TLRI 100/30-36

Load Point					N		A		B	
Standard					ANSI C50.14		ANSI C50.14		ANSI C50.14	
Thermal Classification: Design / Using					F / B		F / B		F / B	
Power			MVA		144.000		144.000		125.000	
Cold Air Temperature			°C		30.0		14.0		52.0	
Voltage			kV		13.800		13.800		13.800	
Voltage Deviation	+	-	%		5.0	5.0	5.0	5.0	5.0	5.0
Armature Current			kA		6.025		6.025		5.230	
Frequency			Hz		60		60		60	
Power Factor			-		0.850		0.850		0.850	
Excitation Requirements	No load I_f	U_f	A	V	396	97	396	91	396	101
	4/4-load I_f	U_f	A	V	1051	257	1051	242	944	241
	5/4-load I_f	U_f	A	V	1270	310	1270	292	1123	286
Cooling Air	Losses		kW		1860		1860		1699	
	Air flow	Temp. rise	m^3/s	K	45.0	39.5	45.0	39.5	45.0	36.1
Short Circuit Currents at No-Load	I_S : 3-phase (peak)		kA		129		129		129	
	I_{K3} : 3-phase (sustained)		kA		9.3		9.3		8.4	
	I_{K2} : 2-phase (sustained)		kA		14.9		14.9		13.4	
Short Circuit Ratio			-		0.582		0.582		0.670	
Reactances	x''_d unsat.	sat.	%	%	16.3	13.2	16.3	13.2	14.2	11.5
	x'_d unsat.	sat.	%	%	21.8	19.6	21.8	19.6	18.9	17.0
	x_d unsat.	sat.	%	%	203	172	203	172	176	149
	x''_q unsat.	sat.	%	%	18.0	14.6	18.0	14.6	15.6	12.6
	x'_q unsat.	sat.	%	%	44.2	40.0	44.2	40.0	37.6	34.0
	x_q unsat.	sat.	%	%	193	164	193	164	168	142
	x_2 unsat.	sat.	%	%	17.2	13.9	17.2	13.9	14.9	12.1
	x_0 unsat.		%		8.4		8.4		7.3	
	x_{leak} unsat.		%		12.7		12.7		11.0	
Time constants at 75 °C winding temperature	T''_d		s		0.031		0.031		0.031	
	T'_d		s		0.862		0.862		0.862	
	T'_{d0}		s		8.664		8.664		8.664	
	T''_{d0}		s		0.042		0.042		0.042	
	T_a		s		0.280		0.280		0.280	
Resistance at 20°C	Stator winding / phase		mΩ		1.31		1.31		1.31	
	Rotor winding		mΩ		191.51		191.51		191.51	
Voltage regulation	PF = rated P.F.		%		28.7		28.7		26.0	
	PF = 1.00		%		21.9		21.9		19.3	
Max. unbalanced load	Continuous		%		8		8		8	
	Short time $i_2^2 * t$		s		10		10		10	
Power at PF = 0	Underexcited		Mvar		68.8		68.8		68.8	
	Overexcited		Mvar		105.1		105.1		90.7	
Winding temp. rise (calculated values)	Stator (RTD)		K		60		58		54	
	Rotor (average)		K		60		57		52	
Total losses			kW		1924		1924		1764	
Efficiences with tolerance at static excitation and rated P.F. (incl. bearing losses)	4/4-load		%		98.45		98.45		98.37	
	3/4-load		%		98.25		98.25		98.09	
	2/4-load		%		97.71		97.71		97.44	
	1/4-load		%		95.90		95.90		95.34	

Generator - Type : **TLRI 100/30-36**

Generator Output	S_N =	144.000 MVA		
Armature Voltage	U_N =	13.800 kV		
Armature Current	I_N =	6.025 kA		
Frequency	F_N =	60 Hz		
Power factor	P.F. =	0.850		
Short circuit ratio	S.C.R. =	0.582		
No load field current	I_{f0} =	396 A		S(1.0) = 18.3%
Nominal field current	I_{fN} =	1051 A		S(1.2) = 85.6%



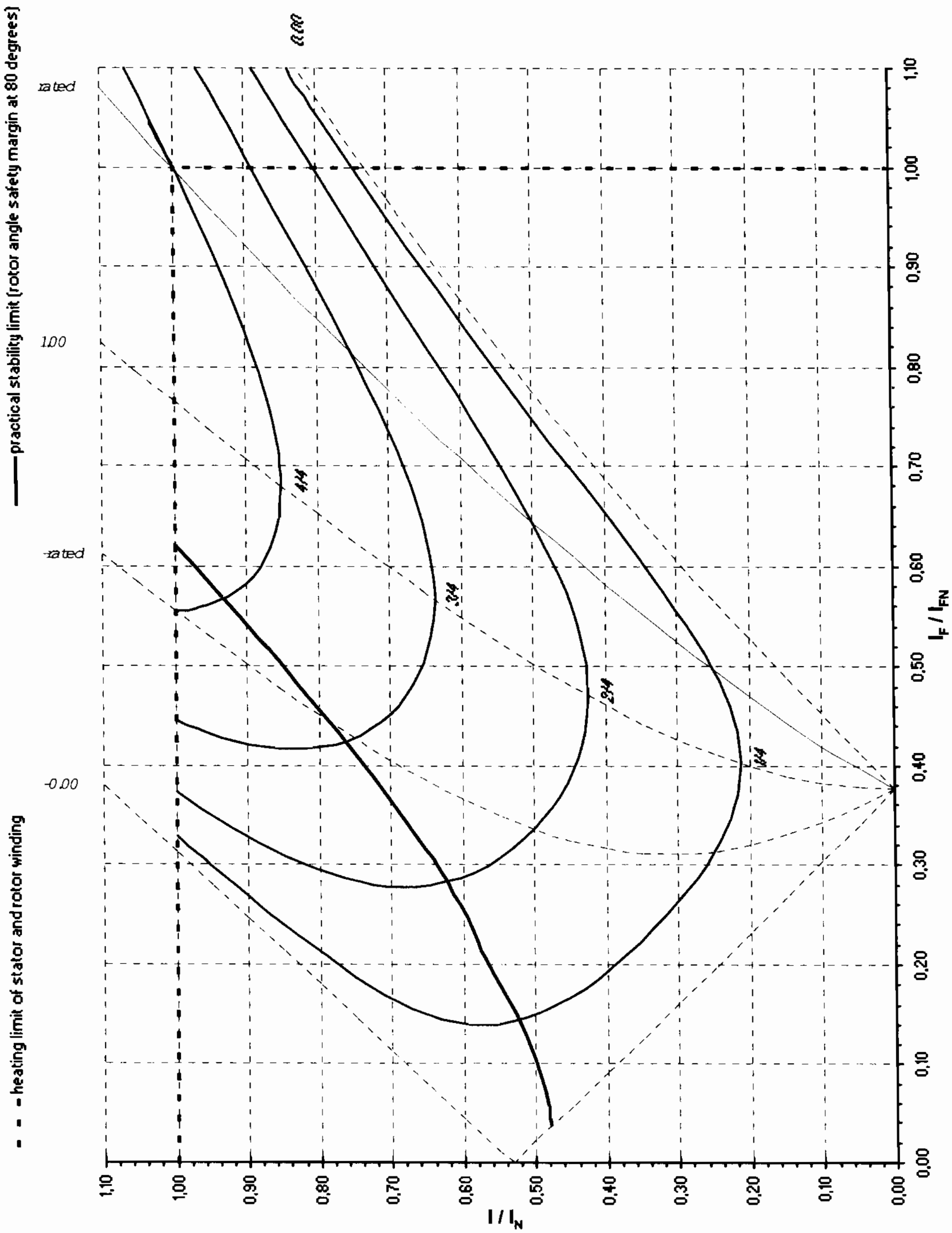
air-gap line — no load saturation - - - - - - short circuit characteristic

Turbogenerator
Description

V-Curves at Rated Voltage

Generator - Type : TLRI 100/30-36

S_N = 144.000 MVA	F_N = 60 Hz	I_{f0} = 396 A
U_N = 13.8 kV	P.F. = 0.850	I_{fN} = 1051 A
I_N = 6.025 kA	T_{Cold} = 30 °C	



Turbogenerator

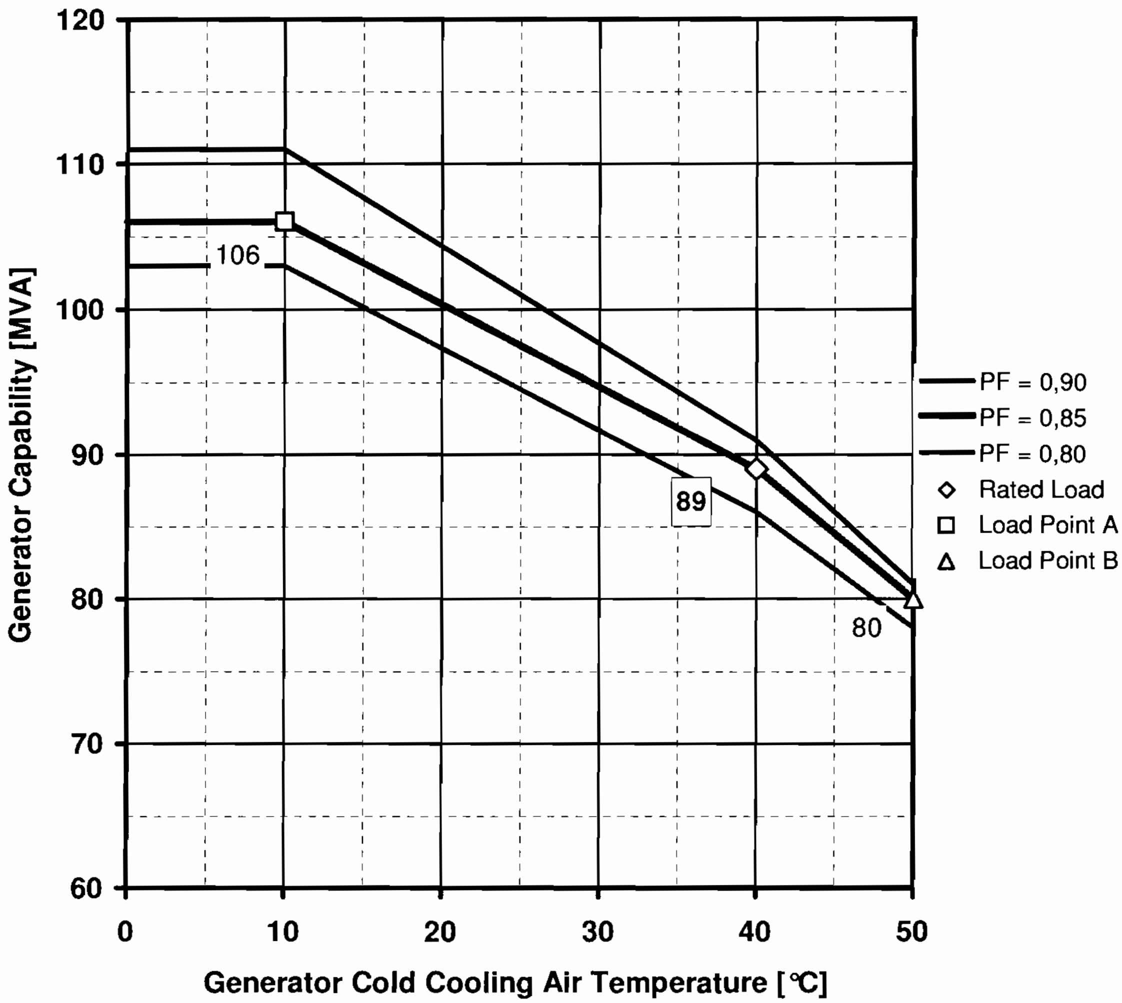
Type-Series 2002

Capability vs. Cold Cooling Air

Generator - Type: **TLRI 86/26-36**

S_N =	89,0	MVA	P.F. =	0,85		$T_{Cold\ Air}$ =	40	°C
U_N =	13,8	kV	f_N =	60	Hz			
I_N =	3,723	kA	n_N =	3600	rpm	Design acc. to ANSI C50 class B		

Generator Cold Cooling Air Temperature [°C]		0	10	40	50
Capability [MVA]	PF = 0,80	103	103	86	78
	PF = 0,85	106	106	89	80
	PF = 0,90	111	111	91	81



GENERATOR

TR02 TLRI 086-26-36 13_8

Electrical Data, Losses and Efficiencies

TR60865

Generator Type: **TLRI 86/26-36**

Load Point						N		A		B	
Standard						ANSI C50.13		ANSI C50.13		ANSI C50.13	
Thermal Classification: Design / Using						F / B		F / B		F / B	
Power				MVA		89,00		106,00		80,00	
Cold Air Temperature				°C		40,0		10,0		50,0	
Voltage				kV		13,80		13,80		13,80	
Voltage Deviation		+	-	%		5,0	5,0	5,0	5,0	5,0	5,0
Armature Current				kA		3,723		4,435		3,347	
Frequency				Hz		60		60		60	
Power Factor				-		0,85		0,85		0,85	
Excitation	No load	I_f	U_f	A	V	360	59	360	57	360	59
Requirements	4/4-load	I_f	U_f	A	V	1120	183	1295	205	1030	168
	5/4-load	I_f	U_f	A	V	1351	220	1583	251	1233	201
Cooling Air	Losses			kW		1221		1455		1114	
	Air flow	Temp. rise		m^3/s	K	28,0	41,7	28,0	49,7	28,0	38,1
Short Circuit	I_S: 3-phase (peak)			kA		63		63		63	
Currents at	I_{K3}: 3-phase (sustained)			kA		5,0		5,8		4,6	
No-Load	I_{K2}: 2-phase (sustained)			kA		8,0		9,2		7,3	
Short Circuit Ratio				-		**0,43**		**0,36**		**0,48**	
Reactances	x''_d	unsat.	sat.	%	%	20,8	16,8	24,7	20,0	18,7	15,1
	x'_d	unsat.	sat.	%	%	29,3	26,4	34,9	31,4	26,3	23,7
	x_d	unsat.	sat.	%	%	246	233	294	277	222	209
	x''_q	unsat.	sat.	%	%	22,8	18,5	27,2	22,0	20,5	16,6
	x'_q	unsat.	sat.	%	%	52,3	47,3	61,1	55,3	47,0	42,6
	x_q	unsat.	sat.	%	%	234	199	279	237	211	179
	x_2	unsat.	sat.	%	%	21,8	17,6	26,0	21,0	19,6	15,9
	x_0	unsat.		%		11,5		13,7		10,3	
	x_{leak}	unsat.		%		16,6		19,7		14,9	
Time constants	T''_d			s		0,031		0,031		0,031	
at 75 °C	T'_d			s		0,772		0,772		0,772	
winding	T'_{d0}			s		6,987		6,987		6,987	
temperature	T''_{d0}			s		0,044		0,044		0,044	
	T_a			s		0,302		0,302		0,302	
Resistance	Stator winding / phase			mΩ		2,58		2,58		2,58	
at 20°C	Rotor winding			mΩ		118,74		118,74		118,74	
Voltage	PF = rated P.F.			%		42,9		47,2		40,5	
regulation	PF = 1,00			%		37,3		41,6		34,8	
Max. unbalanced	Continuous			%		8		8		8	
load	Short time $i_2^2 * t$			s		10		10		10	
Power at	Underexcited			Mvar		33,3		33,3		33,3	
PF = 0	Overexcited			Mvar		71,1		85,3		63,4	
Winding temp. rise	Stator (RTD)			K		67		81		59	
(calculated values)	Rotor (average)			K		75		95		65	
Losses	Bearing losses			kW		85		85		85	
	Windage losses			kW		414		414		414	
	Core losses			kW		175		175		175	
	Short circuit losses			kW		407		577		328	
	Rotor I^2R losses			kW		190		254		161	
	Total losses			kW		1271		1505		1163	
Efficiencies with tolerance	4/4-load			%		**98,35**		98,36		98,32	
at brushless excitation	3/4-load			%		98,22		98,32		98,14	
and rated P.F.	2/4-load			%		97,80		98,02		97,64	
(incl. bearing losses)	1/4-load			%		96,24		96,76		95,88	

GENERATOR

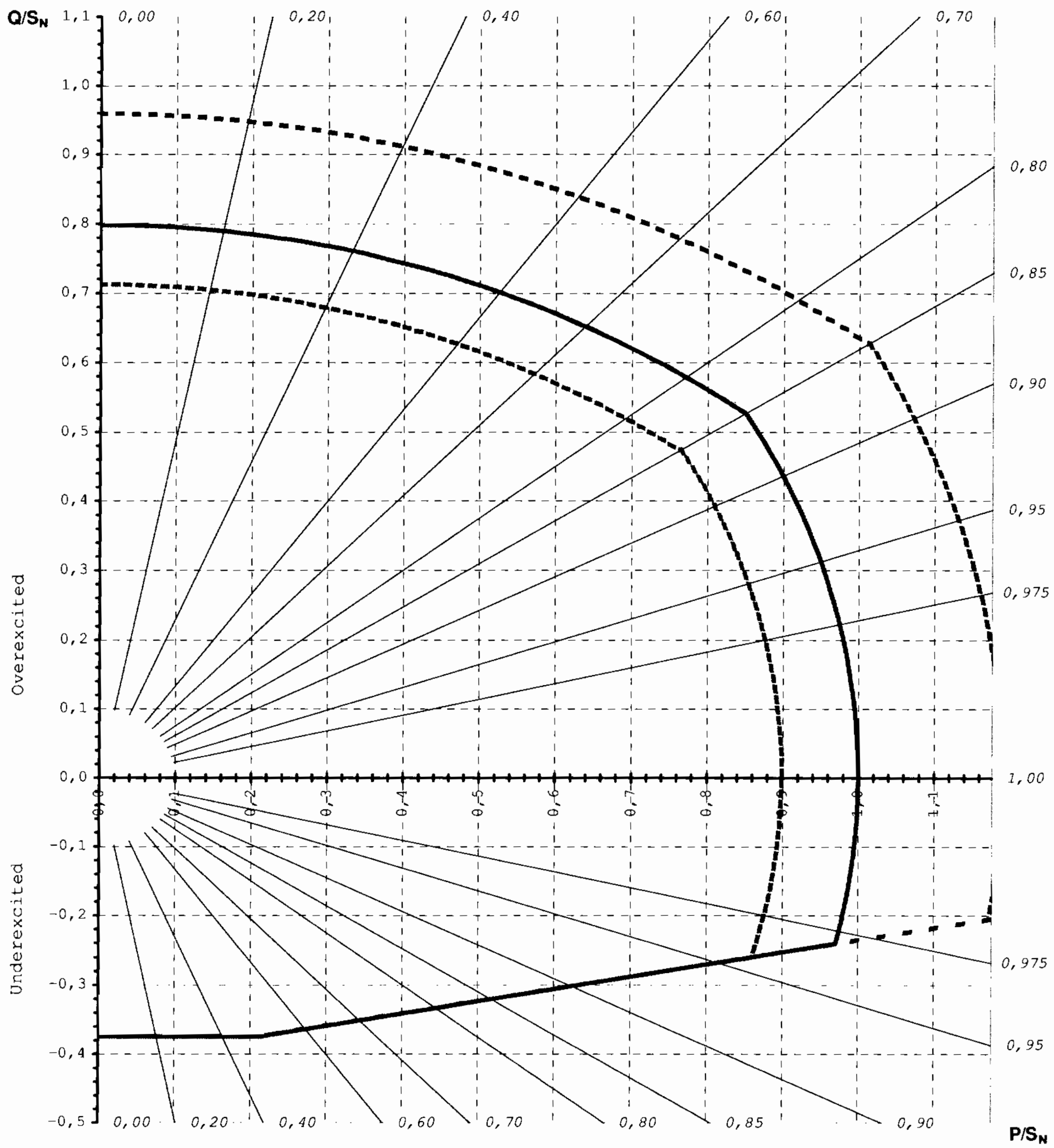
TR02 TLRI 086-26-36 13_8

Reactive Capability Curve

TR60865

Generator - Type: **TLRI 86/26-36**

Load Point	Rated	A	B
S_N	89,00 MVA	106,00 MVA	80,00 MVA
U_N	13,80 kV	13,80 kV	13,80 kV
I_N	3,723 kA	4,435 kA	3,347 kA
f_N	60 Hz	60 Hz	60 Hz
PF	0,85	0,85	0,85
T_{Cold}	40,0 °C	10,0 °C	50,0 °C

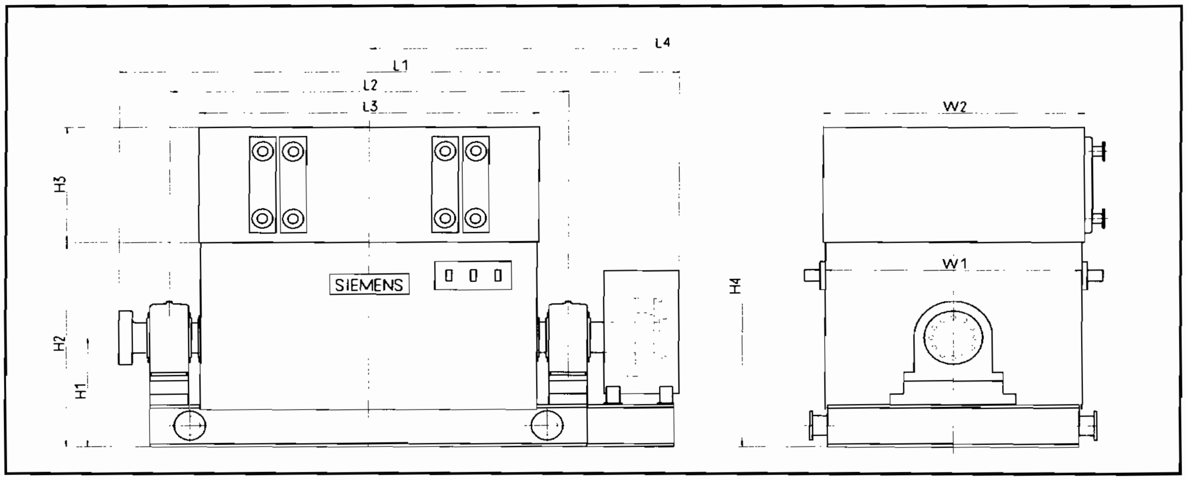


GENERATOR — TR02 TLRI 086-26-36 13_8

Mechanical Data Sheet — TR60865

Generator - Type: **TLRI 86/26-36**

S_N =	**89,00 MVA**	PF =	**0,85**	$T_{Cold\ Air}$ =	**40,0 °C**
U_N =	**13,80 kV**	f_N =	**60 Hz**	$T_{Warm\ Air}$ =	**81,7 °C**
I_N =	**3,723 kA**	n_N =	**3600 rpm**	$P_{V,\ Cooler}$ =	**1221 kW**



Dimensions [mm]:

L1 =	8000	H1 =	1400
L2 =	6000	H2 =	2900
L3 =	5600	H3 [1])=	1200
W1 =	3000	W2 =	3100
L4 =	9900	H4 =	6500
	for rotor withdrawal		crane hook height

Preliminary values.

Exact values are part of detail engineering.

Overall weight:	**102800**	kg
Stator weight:	**83000**	kg
Rotor weight:	**19800**	kg
Rotor moment of inertia:	**1620**	kgm²
Oil flow for both bearings:	**150**	l/min

Thermal time constants [min]:

Stator Winding:	**15,6**	min
Rotor Winding:	**5,7**	min

Estimation for required cooling water[2] flow (for TEWAC - cooling):

$T_{A(cooling\ air)} - T_{W(cooling\ water)}$	Standard water temperature rise	Required cooling water flow
15 K	**10** K	**105** m³/hour
10 K	**7** K	**150** m³/hour
5 K	**3,5** K	**300** m³/hour

1) For cooler in top position.

2) Data are generated independent of cooling method; for DAC- or CACA-applications these data are not applicable.

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	e. Form E

Form E - Firm Capacity Rating (UCAP)

Please provide estimated summer net contract capacities in MW that would be available over the proposed contract term and also indicate any residual firm capacity that would be available to participate in the PJM capacity makets over the life of the proposed project. **The values should reflect the total anticipated PJM UCAP rated capacity over the indicated contract year according to the PJM market rules.**

Please confirm that the capacity will be located within the Delmarva zone.

		Summer		Winter	
Contract Year	**Location (Indicate PJM Zone)**	**Net Contract Capacity (Base)**	**Net Residual Capacity (Supplemental)**	**Net Contract Capacity (Base)**	**Net Residual Capacity (Supplemental)**
6/1/2007 - 5/31/2008	**PERMITTING / CONSTRUCTION / COMMISSIONING**				
6/1/2008 - 5/31/2009					
6/1/2009 - 5/31/2010					
6/1/2010 - 5/31/2011					
6/1/2011 - 5/31/2012	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2012 - 5/31/2013	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2013 - 5/31/2014	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2014 - 5/31/2015	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2015 - 5/31/2016	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2016 - 5/31/2017	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2017 - 5/31/2018	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2018 - 5/31/2019	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2019 - 5/31/2020	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2020 - 5/31/2021	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2021 - 5/31/2022	**END OF CONTRACT TERM**				
6/1/2022 - 5/31/2023					
6/1/2023 - 5/31/2024					
6/1/2024 - 5/31/2025					
6/1/2025 - 5/31/2026					
6/1/2026 - 5/31/2027					
6/1/2027 - 5/31/2028					
6/1/2028 - 5/31/2029					
6/1/2029 - 5/31/2030					
6/1/2030 - 5/31/2031					
6/1/2031 - 5/31/2032					
6/1/2032 - 5/31/2033					
6/1/2033 - 5/31/2034					
6/1/2034 - 5/31/2035					
6/1/2035 - 5/31/2036					
6/1/2036 - 5/31/2037					
6/1/2037 - 5/31/2038					

Additional Notes (use additional sheets as necessary):

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TABS	TITLE

II. **BASE BID PROPOSAL – Application Forms**

f. Form F

Form F - Net Dependable Capacity Rating (Dispatchable Capacity)

Please provide estimated summer net contract capacities in MW that would be available over the proposed contract term and any residual firm capacity that would be available to participate in the PJM capacity makets. The values should reflect the PJM rated capacity over the indicated contract year according to the PJM market rules.

If the proposal includes any additional capacity from duct-firing, steam injection, or any other type of supplemental capacity (incremental to base capacity), please indicate the amounts available under summer and winter conditions. In addition, note any limitations, including but not limited to emission permitting limitations, on the availability of such additional capacity.

Summer capacities be based on an ambient temperature of 92 degrees Fahrenheit ambient air temperature, and appropriate humidity and altitude.

Winter capacities should be based on an ambient temperature of 30 degrees Fahrenheit ambient air temperature and appropriate humidity and altitude.

Please confirm that the capacity will be available within the Delmarva system.

		Summer		Winter	
Contract Year	**Location (Indicate PJM Zone)**	**Net Contract Capacity (Base)**	**Net Residual Capacity (Supplemental)**	**Net Contract Capacity (Base)**	**Net Residual Capacity (Supplemental)**
6/1/2007 - 5/31/2008	**PERMITTING / CONSTRUCTION / COMMISSIONING**				
6/1/2008 - 5/31/2009					
6/1/2009 - 5/31/2010					
6/1/2010 - 5/31/2011					
6/1/2011 - 5/31/2012	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2012 - 5/31/2013	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2013 - 5/31/2014	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2014 - 5/31/2015	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2015 - 5/31/2016	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2016 - 5/31/2017	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2017 - 5/31/2018	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2018 - 5/31/2019	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2019 - 5/31/2020	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2020 - 5/31/2021	**DP&L Bus 23020**	**177**	**0**	**175**	**0**
6/1/2021 - 5/31/2022	**END OF CONTRACT TERM**				
6/1/2022 - 5/31/2023					
6/1/2023 - 5/31/2024					
6/1/2024 - 5/31/2025					
6/1/2025 - 5/31/2026					
6/1/2026 - 5/31/2027					
6/1/2027 - 5/31/2028					
6/1/2028 - 5/31/2029					
6/1/2029 - 5/31/2030					
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6/1/2031 - 5/31/2032					
6/1/2032 - 5/31/2033					
6/1/2033 - 5/31/2034					
6/1/2034 - 5/31/2035					
6/1/2035 - 5/31/2036					
6/1/2036 - 5/31/2037					
6/1/2037 - 5/31/2038					

Additional Notes (use additional sheets as necessary):

* All capacity available for peak operation with water injection is included in the base bid.

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II. **BASE BID PROPOSAL – Application Forms**

g. Form G

Form G - Fuel Plan

1) Please describe the type and design of the proposed boiler:

The facility will utilize unfired Heat Recovery Steam Generators on this project. Heat input is provided from the Combustion Turbine exhaust gas.

The Heat Recovery Steam Generator Sections will be configured horizontally and include HP and LP Steam Generating and Superheat Sections, dedicated Economizers, and a feedwater / preheat system.

2) Identify the primary and secondary fuels used by the project as well as any other alternate fuel capability.

Primary Fuel - Natural Gas (Interstate pipeline quality)

Secondary Fuel - Low Sulfur Light Petroleum Product

3) Provide the following fuel specifications:

Fuel Type	Natural Gas	Sulfur Content	N/A
Heat Content	1.00-1.05 MMBtu/Mcf	Ash Content	N/A
Moisture Content	N/A	Ash Fusion Temp.	N/A

Provide the following fuel specifications:

Fuel Type	LSLPP	Sulfur Content	<0.04%
Heat Content	135,000 - 140,000 Btu	Ash Content	0.01
Moisture Content	<0.10 per volume	Ash Fusion Temp.	N/A

4) Describe the type(s) and source(s) of the fuel:

Primary Fuel Natural Gas - Interstate pipeline quality natural gas as delivered from the TETCO, Transco, or Columbia Gas interstate pipelines

Secondary Fuel: Low Sulfur Light Petroleum Products delivered by Barge from multiple sources from New York, Philadelphia, or Baltimore harbors to the barge unloading facility where it is transferred to the site from an existing pipeline.

Form G - Fuel Plan

5) For each fuel proposed, provide the following information:

- Expected consumption on a daily and annual basis
- Expected maximum instantaneous usage
- An estimate of the percentage provided by each fuel
- The period in which each fuel will be provided (months)
- The percentage of spot or contract volume for each fuel
- Share of contract volumes for contracts of greater than 5 years

a) Nominal Daily Consumption Estimated at 20,000 dt/day / Annual Consumption 5.0 - 6.0 bcf

b) 1421 mmbtu/hr

c) Maximum secondary fuel operation limited to 10% of the total operating hours per year

d) No seasonal restrictions on fuel availability

e) Final fuel portfolio of firm and spot capacity will vary year to year and be adjusted based on the final contract format.

f) Contracts will be negotiated and executed following the successful award and execution of the PPA.

6) List the transporters and describe the transportation routes used to deliver all fuel requirements (primary and secondary) from the source of supply to the plant site. Provide a map depicting the proposed transportation routes from the source of supply to the Project.

The plant will be served by an existing dedicated gas pipeline that connects with 3 interstate gas pipelines - TETCO, Transco, and Columbia Gas. The three pipelines offer supply sources ranging from Texas and the Gulf of Mexico, U.S. Mid continent, and the Appalachian supply areas. Additionally, these pipelines interconnect with many other interstate pipelines to provide reliable and economic options for the plant.

Barge supplies of liquid fuel can be obtained from the New York, Philadelphia or Baltimore markets and delivered via an existing pipe line from the Edge Moor Barge Facility to the Hay Road site. Note that the Edge Moor Barge facility is owned and operated by Conectiv Energy.

7) Describe the types (firm or interruptible) and terms and conditions of all transportation arrangements proposed for all transportation segments from the fuel supply source to the Facility site, and provide copies of all such transportation arrangements.

CESI currently has contracts with TETCO and Columbia Gas that deliver nearly 100,000 dt/day of gas to the existing plant site on a firm basis. CESI participates in the released capacity and firm delivered gas markets for periods from 1 day to many years. CESI has NAESB contracts and credit arrangements in place with pipelines, producers, marketers, and gas utilities. Also given the nature of the NE gas markets, interruptible capacity is available for most months of the year.

Form G - Fuel Plan

8) Indicate if transportation service is to be provided via existing capacity or if new capacity is required to provide such service. In the event new capacity is required, Bidder shall provide all relevant information relative to the proposed capacity arrangement in sufficient detail to allow the Proposal's feasibility to be evaluated.

CESI would serve the facility in part with gas capacity currently under contract.
These contracts can be renewed by CESI to cover the PPA period. Additionally CESI will
negotiate with the suppliers for additional firm capacity and other required pipeline agreements that may
be needed to meet the gas delivery needs for the plant.

9) Provide all pricing arrangements, tariffs and/or pricing assumptions for all separate transportation segments. Explain the basis for the transportation price assumptions.

Pricing (demand charges) of recent incremental pipeline capacity projects in this market area
has ranged as high as $0.55 per dt, depending on receipt and delivery point.
All interstate pipeline tariffs and their terms and conditions can be found on each of the
pipeline supplier's websites.
Final contract terms for full gas delivery are not in place at this time. The proforma assumptions
in this proposal utilized existing pricing structures and current commercial arrangements
combined with forward market forecasts.

10) Provide a description of the sources of fuel supply for the Facility, and list the names of the proposed fuel suppliers.

CESI has NAESB contracts and credit agreements in place with dozens of suppliers, storage
holders, marketers, financial entities, and utilities to manage the 20-25 Bcf of annual gas needs
for its existing generation fleet. CESI buys physical supply in the Gulf and Appalachian zones
to move on our pipeline transport or put into storage. CESI also buys firm delivered gas and
physical options as required. CESI also has the appropriate financial and risk management
agreements and systems in place to manage the fuel pricing component of this proposal.
For Low Sulfur Light Petroleum Products, CESI has relationships with various marketers in
New York, Philadelphia, and Baltimore.

Form G - Fuel Plan

11) Provide copies of all fuel supply arrangements or proposed arrangements. Include all terms and conditions applicable to the arrangements including:

- Term
- Volume commitments
- Pricing arrangements/components
- Minimum take requirements
- Acceptable contract terms and conditions
- Status of the arrangements
- Price re-openers
- Volume flexibility/penalties
- Market out provisions
- Performance guarantees
- Lead time on arranging or nominating gas supply for delivery
- Quality specifications for all fuels

CESI will assemble an appropriate portfolio of gas transport, storage and supply as well as the required liquid fuel needs that is consistent with the energy pricing proposed in the PPA. The supply portfolio will include both the expected physical supply needs of the plant as well as the financial instruments and options that would be used to manage the fuel commodity portion of the submitted energy offer.

12) Provide a description of the fuel pricing arrangements for both the primary and secondary fuels including the fuel price index utilized as well as any escalation factors or any other costs to the company, any price floors or ceilings, and any price variation based on load factor or other provisions.

For natural gas, the submitted energy pricing is based on an annual gas cost at the Henry Hub plus a transportation charge for delivery (basis) to the plant. For years where Henry Hub pricing is not available, an annual escalation of 2.5% will be used from the last available year. For liquid fuel, pricing will be based on a Platt's oil index plus related transportation charges.

Form G - Fuel Plan

13) Provide information that describes if and how the fuel pricing arrangements are integrated with the terms of the proposed PPA. Discuss if there are any limitations in the fuel supply arrangements that could affect unit dispatch or translate into a constraint on unit operations.

The pricing of the PPA is the result of CESI's analysis of all expected costs to deliver fuel to the plant. These include physical commodity, gas pipeline transport and upgrades, gas storage needs and all costs associated with liquid fuel storage and delivery.

Fuel would be available at the plant except under Force Majeure conditions.

14) Provide copies of supplier's annual reports, marketing and financial information that illustrate the financial and market strength of the supplier and its experience in supplying fuel to power Facilities.

CESI will procure and manage all the fuel needs, both physically and financially, of the plant as required to support this offer. The fuel sources referenced through this document are major transporters and are well equipped to support this project.

CESI has a long standing history with the referenced fuel suppliers for this proposal who meet the daily needs for providing fuel for the 3600 MW currently managed by Conectiv Energy including the existing 2000 MW of Combined Cycle technology applied in this proposal.

15) Provide a description of Bidder’s experience in securing fuel supply and transportation arrangements for other Facilities of similar size, technology and fuel type.

Conectiv Energy has operated a portfolio of more than 3600 MW of base load, combined cycle, and peaking generation for over 10 years. For the last 5 years, Conectiv Energy's dual fuel combined cycle fleet has been nominally 2000 MW. Conectiv Energy had oversight for the combined cycle engineering and construction activities. The O&M, fuel procurement, and PJM dispatch activities for the combined cycle plants have also been managed by Conectiv Energy.

Form G - Fuel Plan

16) Describe the fuel inventory and management procedures followed by the Bidder. Include in the response, a description of the planned inventory maintained for the Facility on both a volumetric basis and based on number of days or hours at full unit output; whether the inventory will be maintained on-site or off-site; and the on-site or off-site storage capacity available. For storage capacity, indicate if it is on-site or off-site storage, identify the volume of storage capacity, and the number of days or hours at full output which the storage facilities could sustain.

For natural gas, it is expected that CESI will own high volume storage in the Gulf region to support 10 days of on-peak plant operation. This storage will be connected to firm interstate pipeline transport for reliable fuel delivery. It is expected that CESI will purchase physical options for delivered gas from market area sources as a supplement to the Gulf area storage.

For liquid fuel, there is a 250,000 bbl storage tank on site that currently serves the existing Hay Road Power Complex. (HRPC)

17) Provide a description of Bidder's fuel supply strategy and criteria that serves as the basis for evaluating and selecting fuel suppliers and transporters.

As described previously, Conectiv Energy has owned and operated a fleet of more than 3600 MW of generation, including all fuel procurement and management requirements for over 10 years.
CESI has in place all the necessary contracts with brokers, marketers, and financial entities to supply all the fuel needs for the units.
CESI's energy professionals have the expertise and the internal processes in place to manage both physically and financially such fuel activities. CESI's risk and credit staff monitor the financial health of our suppliers on an ongoing basis.

18) For energy sale bids in which bidder plans to acquire and manage the fuel supply, describe supply plan and identify all contracts that support the supply of firm gas transportation and firm supply to the proposed plant.

Please see the responses to Questions 6 through 17 of Form G

Form G - Fuel Plan

19) For gas-fired facilities, identify the pipeline to which the bidder plans to interconnect.

By way of a direct dedicated lateral, the plant will be connected to 3 interstate pipelines - TETCO, Transco, and Columbia Gas

20) Describe the gas interconnection facilities that will be needed including the size, length and location of the lateral interconnection and fuel delivery point (attach a USGS-based map showing the gas pipeline delivery point, the location of any lateral lines, compressors and meters.)

There is gas infrastructure currently in place to serve existing facilities. No system upgrades are anticipated at this time. See the USGS map and sketch attached to this section.

21) If known, please indicate the total assumed capital costs for all gas facilities that are estimated.

No system upgrades are expected to be required.

22) If secondary on-site fuel storage is proposed, describe the fuel type, including quality specifications, quantity, and maximum number of full-load run hours on secondary fuel.

For liquid fuel, there is a 250,000 bbl storage tank on site. Assuming 90% draw capacity, > 1000 hours of operation which exceeds the expected total hours for the year. Calculation assumes no other units are operating on oil during this period and tanks are full.

23) Indicate the gas delivery pressure required at each of the following points.

plant burner tip pressure:	**220 psig**
gas interconnection point:	**200 minimum psig**
gas interconnection point:	**750 maximum psig**

24) Identify the pressure **guaranteed** by the interconnecting pipeline at the fuel delivery point.

There is no guaranteed minimum pressure

25) Indicate the maximum daily and hourly gas consumption at the proposed plant and the amounts required on a firm a basis:

	Summer	**Winter**	**Comment**
Maximum Daily Consumption (mmBTU/day)	34,100	31,941	Assumes Peak Mode; 24 hrs/day
Maximum Hourly Consumption (mmBTU/hr)	1,421	1,331	Assumes Peak Mode; 24 hrs/day
Expected Daily Consumption (mmBTU/day)	16,789	20,368	Base Mode; 16 hrs/day (Peak Period)
Expected Hourly Consumption (mmBTU/hr)	1,049	1,273	Base Mode; 16 hrs/day (Peak Period)

Form G - Fuel Plan

26) List any gas quality restrictions and indicate if the required delivery pipelines have acceptable gas quality.

The installed Generation equipment at the existing site and to be used in this expansion project will require pipe line quality gas. Historically, since initial operation at the site since the early 1990's, pipe line quality gas has not been an issue. No restrictions or limitations will be invoked for this project.

27) Describe the fuel transportation / supply plan, including all railroad(s), truck routes, quantities and frequencies. Explain any highway or rail improvements that may be necessary to accommodate the proposed transportation plan, such as paving, bridges, new spurs, etc., as well as plans for accomplishing such improvements.

All infrastructure for the delivery of Natural Gas and Low Sulfur Light Petroleum Products are currently in place. Accordingly, no upgrades or improvements will be required.

28) Identify all rail carriers and describe the status of any transport negotiations or agreements, including any known or anticipated freight rates.

N/A

Form G - Fuel Plan

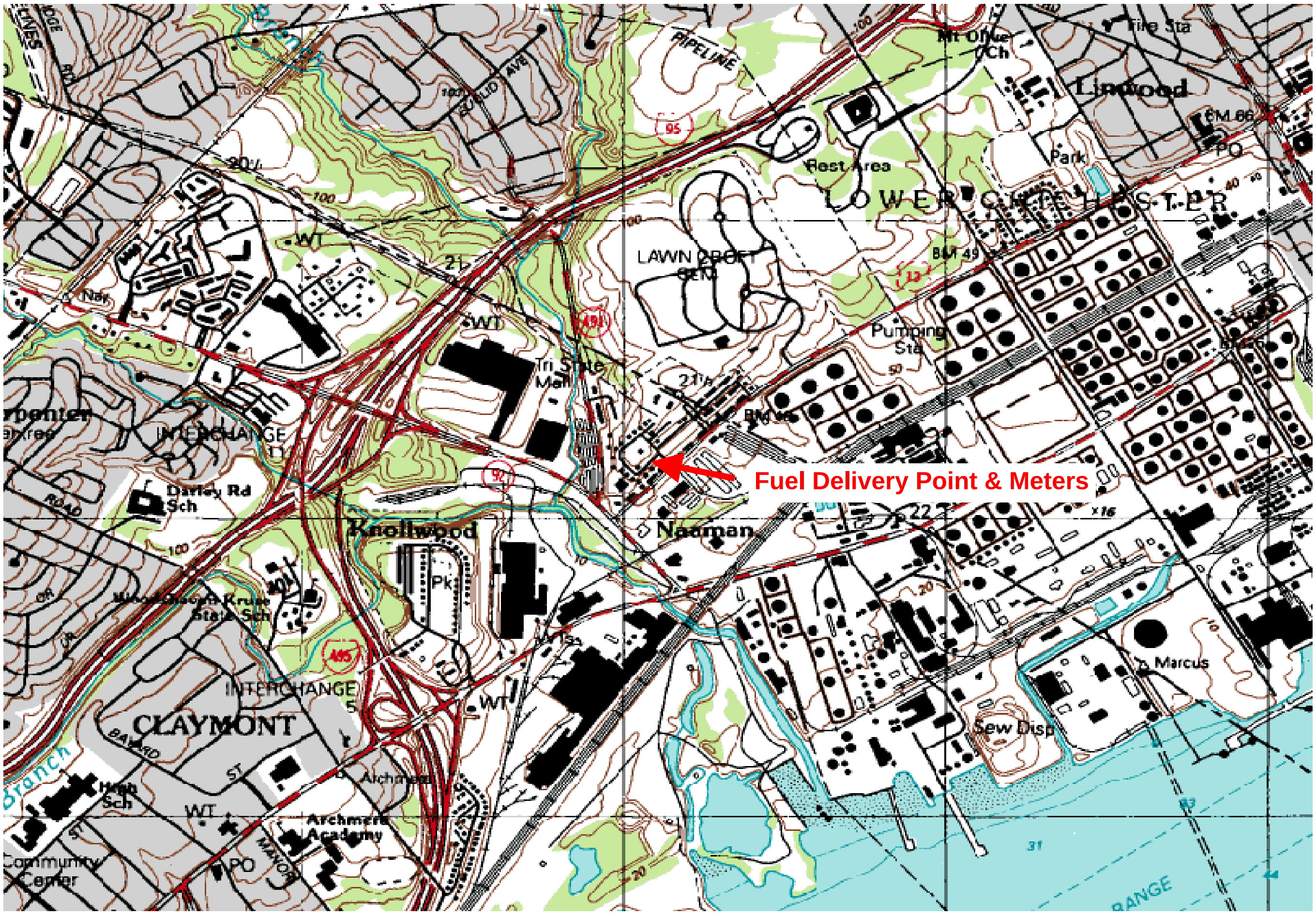
29) For wind and other renewable resource projects, please provide the following:

a) A summary description of the resource studies used for the specific sites;
b) A statement of the period for which data were collected and the sites from which those data were collected;
c) A summary of the qualifications of the parties who prepared the resource studies; and
d) A projected average net output in MWh in a 12 x 24 matrix (for each hour, indicate the average number of MWh expected to be generated) showing total expected monthly and annual output (and stating the expected capacity factor).

N/A

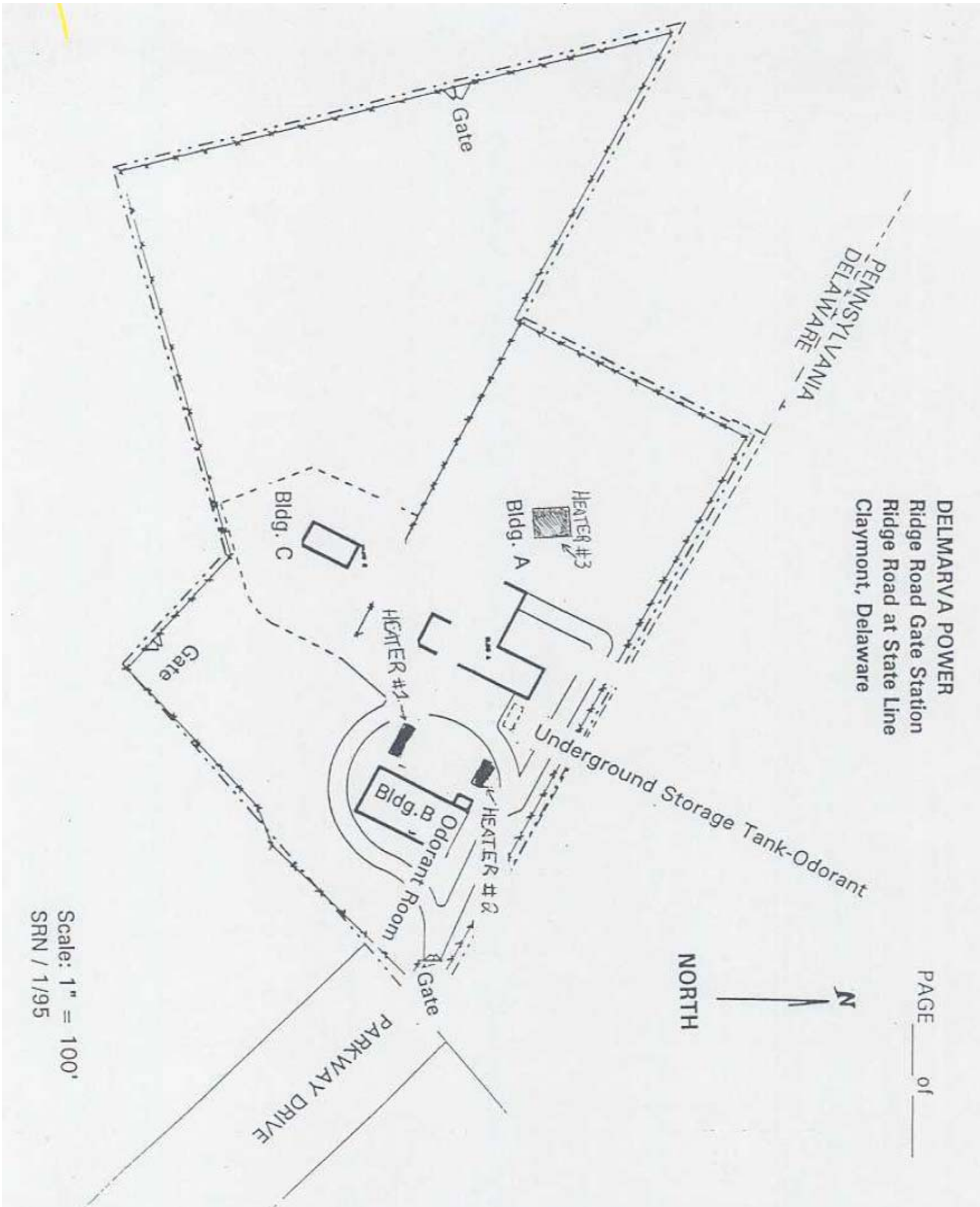
Form G - Fuel Plan

QUESTION 20 SHEET 1 OF 2



Form G - Fuel Plan

QUESTION 20 SHEET 2 OF 2



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II.	**BASE BID PROPOSAL – Application Forms**
	h. Form H

Form H - Environmental Impact - Air Emissions

Please provide the following emission rate information for proposed generator(s), including supplemental capacity (duct-firing, steam injection, etc.), if applicable.

Emission Rates on **Primary Fuel: [Gas firing in Pre-Mix Mode - See Note 1]**

	Base Capacity (lb/MMBtu)	**Full Load w/ Supplemental Capacity (lb/MMBtu)**
Oxides of Sulfur	0.003	
Oxides of Nitrogen	0.01	
Carbon Dioxide	117.08	
Carbon Monoxide	0.018	
Volatile Organic Compounds	0.00168	
Particulate Matter - PM10	0.021	
Particulate Matter - PM2.5	0.021	
Lead	N/A	
Mercury	N/A	

Maximum NOx emission rate (in parts per million):	3
Maximum CO emission rate (in parts per million):	9
Maximum permitted/permittable annual capacity factor (%):	See Note 2

Emission Rates on **Secondary Fuel** (if applicable): **Low Sulfur Light Petroleum Product (See Note 1)**

	Base Capacity (lb./MMBtu)	**Full Load w/ Supplemental Capacity (lb/MMBtu)**
Oxides of Sulfur	0.04	
Oxides of Nitrogen	0.054	
Mercury	N/A	
Carbon Dioxide	159.535	
Carbon Monoxide	0.021	
Volatile Organic Compounds	0.00175	
Particulate Matter	0.039	

Maximum NOx emission rate (in parts per million):	14
Maximum CO emission rate (in parts per million):	9
Maximum permitted/permittable annual capacity factor (%):	See Note 2

Form H - Environmental Impact - Air Emissions

Indicate if Facility is capable of CO2 capture. If yes, describe the potential methods for capture and associated costs.

The proposed facility is not designed to utilize CO2 capture , although potential does exist for retrofit capability should sequestration technology mature and become commercially available.

Additional Notes:

1. Emission rates are estimates at base load and iso conditions. Final permit limits will be defined during the permitting process.
2. The facility will attain sufficient emission offset to operate at or above the forecasted total capacity factor of 48% for primary and secondary fuels. The maximum capacity factor based on review of the RFP for this unit will be 55% and is based on an estimated 4000 hours in Pre-Mix mode, 400 hours of gas diffusion, and 400 hours of LSLPP operation.
3. Data reported for CO_2 emissions are based upon generic emission factors and reported on a lb of CO_2 per million BTU ***heat input*** basis. Combined cycle technology utilizes waste heat to produce additional megawatts through a secondary steam cycle without the need for additional fuel combustion. Therefore, emissions associated with the use of this technology on a comparative basis, are about one third less than emissions from con-

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II.	**BASE BID PROPOSAL – Application Forms**
	i. Form I

Form I - Environmental Impacts/Permits - Air and Water

1) Describe all air quality permits that will be required for the project.

The proposed facility will be deemed a "major modification" to the Hay Road Facility and as such will need to comply with DNREC Reg. 25, Requirements for Preconstruction Review and Reg.1102 Permits. The facility will need to undergo a Best Available Control Technology (BACT) Review for PSD pollutants emitted in significant quantities, and a Lowest Achievable Emission Rate Review (LAER) for non attainment pollutants (e.g. NOx). The facility will also need to secure emission offsets for NOx - which will be proposed by further reducing NOx emissions from one of the existing Hay Road Units (1, 2,or 3) through the implementation of SCR technology. Construction Permits and Operating Permit modifications to accommodate the proposed offsets will need to be secured. In addition, the new facility will need Acid Rain Permits, and a Title V Operating Permit.

2) State whether any air permits have been secured, and if not, whether applications have been filed. Report on the status of any pending applications and any feedback from permitting agencies.

No regulatory permit applications have been submitted for the proposed facility. Permit applications will be initiated immediately following the contract award.

3) Describe the expected time frame to obtain the necessary air permits after application submittal to the State including the expected dates of filing the permit applications.

The proposed technology replicates the existing technology currently in use at the site which was reviewed and permitted by DNREC in the last five (5) years. Regulatory approvals always include uncertainties, but a conservative estimate would be that air permits would be obtained in approximately 16 - 18 months from contract award. The unique operating experience and known characteristics will limit permit preparation time to several (3 - 5) months from contract award.

Form I - Environmental Impacts/Permits - Air and Water

4) Describe all other federal, state and local environmental permits and approvals that will be required, including but not limited to federal environmental assessments under the National Environmental Policy Act (EA/EIS), wastewater discharge permits, hazardous waste permits, etc. Report on the status of all such permit applications and any feedback from permitting agencies.

Based on the specific site characteristics, the Major Permits Include:
DNREC Reg 25 Prevention of Significant Deterioration/ Non Attainment Approval, Acid Rain Permit, Delaware Coastal Zone Permit Approval - Environmental Assessment (as an existing manufacturing use), Delaware River Basin Commission Water Use Approval, DNREC NPDES
Permit Approval (Modification to existing Edge Moor Power Plant for 316 A thermal impacts assessment, New Castle County Wastewater Discharge Permit Modification to Sewer system, DNREC Reg 1146 Construction Permit Approval, New Castle County Land Development Approval (Environmental Assessment), Soil Erosion and Sediment Control Plan, Storm Water Management Plan, DNREC Facilities Permit, US Dept of Energy Fuel Use Act Certification, Fed Aviation Admin Stack Height Approval.

5) Describe the water supply strategy for the project, including a description of water requirements, water supply source(s), discharge plans, new water pipeline requirements, and any work completed to date on the water supply plan.
Discuss how impingement/entrainment issues will be addressed.

The water supply strategy proposed for this project, is based on Conectiv Energy's previous expansion of its adjacent HRPC. As such, the potable and plant service water will be obtained from municipal sources via existing supply pipelines to the HRPC. Condenser and cooling tower makeup water will by obtained from the existing EMPP once-through cooling water discharge canal.

The advantages of this approach are several. Obtaining potable and plant service water from municipal sources will ensure consistent water quality requiring minimal onsite treatment, and will eliminate the need for groundwater withdrawal and treatment systems. Conectiv Energy will also utilize its existing HRPC water treatment and demineralized water storage facilities. Upgrades to this proven system, if required to accommodate the proposed project, is more viable and cost effective than development (i.e., siting, permitting, and construction) of a new, stand-alone treatment and storage facility. - continued

Form I - Environmental Impacts/Permits - Air and Water

The principal benefit of obtaining cooling tower makeup/condenser water from the "hot-side" of EMPP's existing cooling water discharge canal is to eliminate the need for a new surface water intake [along with its associated 316(a) and 316(b) issues that require very lengthy permit lead times]. This design has proven to be an efficient solution for HRPC's Units 4 and 8, eliminates any concern regarding impingement and entrainment issues, and can be accomplished via a tap into the existing HRPC Unit 4 or 8 intake pipelines from the discharge canal. The resulting blowdown will be returned via a short, new pipeline to the existing HRPC Unit 4 or 8 discharge to the EMPP cooling water discharge canal. As demonstrated in the successful prior permitting of the similar Hay Road Unit 4 and 8 designs, this commingled discharge will discharge to the Delaware River via existing EMPP Outfall 001, and result in an actual improvement to the current discharge temperature.

6) Describe any benefits to long-term air and water quality anticipated to result from the facility.

As required under Delaware's Coastal Zone Permit Regulations, affected sources must "more than offset" their actual environmental impacts for all media. This would, for example, go beyond the federal and state Clean Air Act requirements for non attainment pollutants emitted above threshold quantities. Conectiv proposes to offset its actual air emissions from the proposed facility by retrofitting SCR technology on one of the existing Hay Road Units (1, 2, or 3) in order to provide equivalent NOx emission offsets for NOx and other conventional regulated pollutants emitted from the new facility.

The water supply strategy proposed for this project is been shown to result in numerous long-term benefits and minimal impacts due to its location adjacent to the existing HRPC. Briefly, these benefits include utilization of existing infra-structure, thus eliminating most of the typical impacts to sensitive ecological resources usually associated with development of rights-of-way or Greenfield site. Under the proposed approach impacts to resources such as wetlands, shorelines, inter-tidal and near-shore areas from new rights-of-way, pump houses, and intake/discharge structures are either eliminated or minimized. Delaware's Coastal Zone requirements can be met based on existing facilities and compatible zoning and land use. EPA and Coast Guard review and approvals will be minimized or eliminated since no new intake or discharge will be required. Impacts to the fish and other aquatic fauna will be eliminated, and may be improved due to the reduced discharge temperature at EMPP outfall. (No. 001)

7) Describe the control technology which will be utilized at the facility for control of air emissions. Describe any performance guarantees related to specific control equipment.

The proposed facility will use gas dry premix combustion technology in order to limit NOx emissions when firing gaseous fuel in the primary mode of operation. The use of the Siemens unique silo combustors also limits the formation of VOC and CO emissions at all loads without the need for the use of CO catalyst technology. Flue gas NOx emissions are further reduced through the use of Selective Catalytic Control Reduction (SCR) technology. In the liquid fuel firing modes, water injection is used to limit NOx emission prior to the use of SCR technology.

Form I - Environmental Impacts/Permits - Air and Water

8) In anticipation of future environmental control programs, describe the expected capability to reduce air or water emissions. Options may include additional control equipment, modified operations, reduced operations, etc. Include in your description the feasibility of and anticipated degree of difficulty of each option.

The facility will utilize the Best Available Control Technology at the time of construction.
The proposal, as configured, is unique and allows for daily shutdown and turn down capability.
This will minimize annual plant emissions when not required to meet load demands and
allow non-cycling and lower cost PJM units to operate at loads above minimum load
where excess air impacts emissions and efficiencies.
This feature benefits the environment and provides financial benefits.

With regard to water resources and aquatic impacts, the proposed use of existing once
through cooling water has been shown to reduce aquatic impacts in previous Hay Road
applications, and will allow the environmentally conscience use of water for
consumptive use.

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II.	**BASE BID PROPOSAL – Application Forms**
	j. Form J

Form J - Environmental Impact Hazardous Waste

Describe Environmental Effects of Power Plant Construction and/or Operation on the following:

1) On-site Treatment, Storage, Disposal Facilities

Hazardous waste associated with a facility such as the proposed power plant consists primarily of potentially flammable substances (gas pipeline condensate, small amounts of water treatment chemicals and volatile compounds). Based on the siting, design, and operational requirements of Conectiv Energy's proposed power plant, the environmental effects of power plant construction and/or operation of onsite treatment, storage, and disposal facilities will be minimal. Regarding construction, the plant will be sited on a cleared upland portion of an industrially zoned brown field site. This location lacks potentially sensitive environmental or land use resources (eg., wetlands, surface waters, endangered species, aesthetic or cultural resources). Regarding operation, the proposed plant will utilize the existing state-of-the-art waste handling, treatment, and storage facilities in the adjacent facility which operate in full compliance with applicable federal, state, and local regulations and guidelines. Based on the typical operations of the similar Hay Road units, the proposed facility should qualify under either the Small Quantity Generator or Conditionally Exempt Generator status.

2) Off-site Transportation

Any hazardous waste generated during construction or operation will be stored in designated, clearly identified storage areas prior to off-site transport to approved waste disposal facilities by licensed hazardous waste contractors.

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II.	**BASE BID PROPOSAL – Application Forms**
	k. Form K

Form K - Environmental Impact Land Impacts

Describe Environmental Effects of Power Plant Construction and/or Operation on the following:

1) Wetlands

Conectiv Energy's proposed plant has been sited on an upland portion of an industrial site which does not support or adjoin jurisdictional wetlands. Similarly, the utilization of existing infra-structure (e.g., roads and utility rights-of-way) will avoid impacts to freshwater or tidal wetlands by linear facilities. The facility has been located on this brownfield site to specifically avoid wetland impacts. During construction potential stormwater runoff impacts to offsite wetlands will be controlled under County-approved Soil Erosion and Sediment Control Plan. During operation, such impacts will be avoided through development of an approved Stormwater Management Plan and system.

2) Terrestrial Environment (Wildlife, including Avian Protection)

The proposed power plant will be located on a cleared brownfield site that has been previously used as staging and laydown area for the adjacent power plants. The site supports no wildlife habitat or resources, is surrounded by other onsite and offsite industrial facilities, and does not provide or adjoin natural habitats suitable for wildlife or related ecologically important resources such as wading bird colonies. Construction and/or operation of the facility at this proposed site will have no impacts to the terrestrial environment.

3) Aquatic Environment (Fish and Aquatic Organisms)

The project site does not support or adjoin aquatic habitat. Stormwater runoff impacts to offsite aquatic habitat (i.e., the Delaware River) are avoided through implementation of the soil erosion and sediment control measures (construction phase) and a stormwater management system (operation). Potential operational impacts to the aquatic environment from impingement or entrainment at the surface water intake are eliminated via the utilization of the Edge Moor Power Plant's once-though cooling discharge. Moreover, this design will also result in the lowering of the exiting Edge Moor discharge temperature, resulting in an additional environmental benefit. Since the proposed design will utilize existing intake and discharge facilities in the Delaware River the need for dredging or filling in any aquatic environment is eliminated.

4) Threatened and Endangered Species Protection

The proposed project site supports no onsite natural terrestrial or aquatic habitats, is located in a highly developed and industrially zoned area, and onsite and surrounding land uses preclude the presence of threatened or endangered species. The absence of such species was further verified in a series of previous site surveys.

Form K - Environmental Impact Land Impacts

Describe Environmental Effects of Power Plant Construction and/or Operation on the following:

5) Delaware Coastal Zone

The proposed project site is located within the boundaries of Delaware's Coastal Zone. However, Conectiv Energy's existing Hay Road Power Complex has been successfully permitted as an allowable use as recent as 1999. In fact, the expansion of HRPC's Units 5-8 was successfully accomplished under the first Coastal Zone offset requirement revisions.

6) Agricultural Areas

The proposed project site adjoins the eastern portion of the City of Wilmington in New Castle County and does not support or adjoin agricultural areas.

7) Corridors needed to connect to fuel sources and the electric transmission grid

The proposed project site has been selected, in part, based on the availability of existing infra-structure. Based on Conectiv Energy's proposed site and plant design no offsite corridors for fuel lines, transmission lines, or water intake and discharge lines will be required for this project

8) State-designated Scenic Byways

No state-designated scenic byways exist in the vicinity of the project site. Hay Road and Interstate 495 are the two roads in the vicinity of the site.

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II. BASE BID PROPOSAL – Application Forms

l. Form L – Complete with Attachments

Form L - Site Development General

1) Indicate whether bidder controls the development site through a) ownership of a leasehold interest in, or a right to develop a site for the purpose of constructing the proposed generating facility; b) an option to purchase or acquire a leasehold site for such purpose; c) an exclusivity or other business relationship between bidder and the entity having the right to sell, lease or grant bidder the right to possess or occupy a site for such purpose; or d) fee simple.

The land for the proposed project is owned by Conectiv Delmarva Generation, Inc. a fully owned subsidiary of Conectiv Energy Holdings. Conectiv has full development and ownership rights to the site.

2) If site control described in 1) above has not yet been secured, describe plan and schedule for obtaining such site control.

N/A

3) Indicate if the proposed development site has an appropriate zoning designation, or whether a rezoning is necessary. Describe any rezoning plans and issues.

Conectiv Energy's proposed project site is zoned M-3, Heavy Industrial, a zoning designation that is entirely consistent with the proposed project. No rezoning is necessary.

4) Describe all city or county land use permits that will be required such as conditional use or special use approvals.

The property is zoned Heavy Industrial and therefore special use permits are required.
To proceed with Construction, County and City permits would include:
1) New Castle County Land Development and Soil Erosion Permits
2) Building and Occupancy Permits
3) New Castle County Wastewater Discharge Permit Modification to Sewer system
4) New Castle County Council Approval
5) State Fire Marshall Plan Approval

Form L - Site Development General

5) Report on the status of land use permitting activities, including the status of any pending applications and any feedback from permitting agencies, community or neighborhood groups.

No permit applications have been developed or submitted to date. Permitting of the Hay Road expansion in 1999 was approved by local, state, and federal agencies. There are no land use changes required and the proposed use is consistent with the existing site use.

6) Describe existing and planned land uses in all directions surrounding the proposed development site.

The existing land uses surrounding the proposed project site consist of generally heavy industrial and manufacturing facilities, major transportation corridors (Amtrak rail corridor, I-495), the City of Wilmington's Wastewater Treatment Plant and associated sludge stabilization facilities, and the Cherry Island Landfill. Conectiv Energy is not aware of any planned land use changes that would change the character and land use pattern of this general area.

7) Indicate the total acreage of the proposed site: 6 acres

8) Indicate if the site is an existing brownfield or industrial location: __X___ Yes ______No

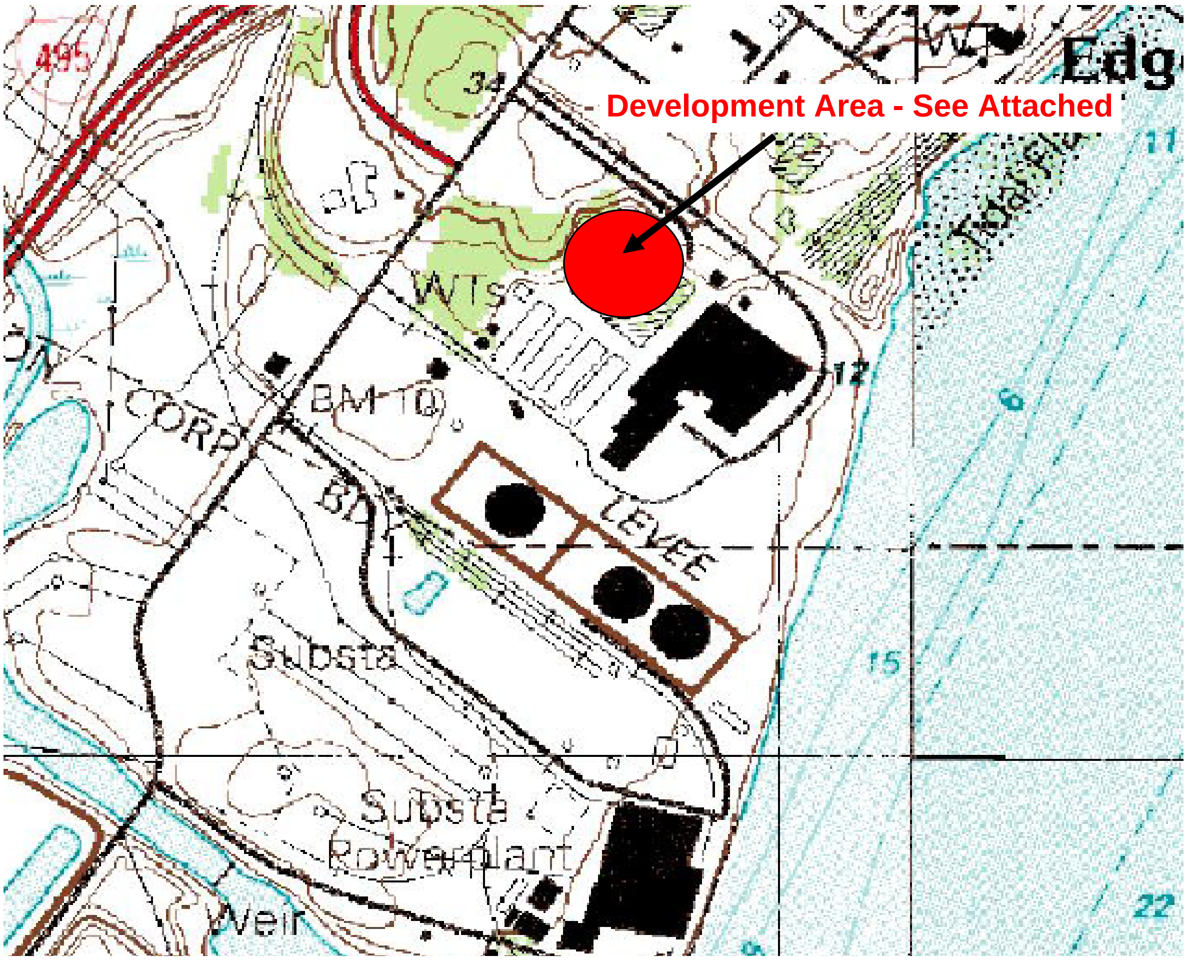
9) Attach a USGS-based map showing the location of the proposed development site and the anticipated placement of all facilities at the site including transmission and fuel related facilities.

10) Attach a complete Project Development and Construction Schedule

See attachment

Form L - Site Development General

ATTACHMENT I: QUESTION 9 - USGS MAP OF PLANT LOCATION



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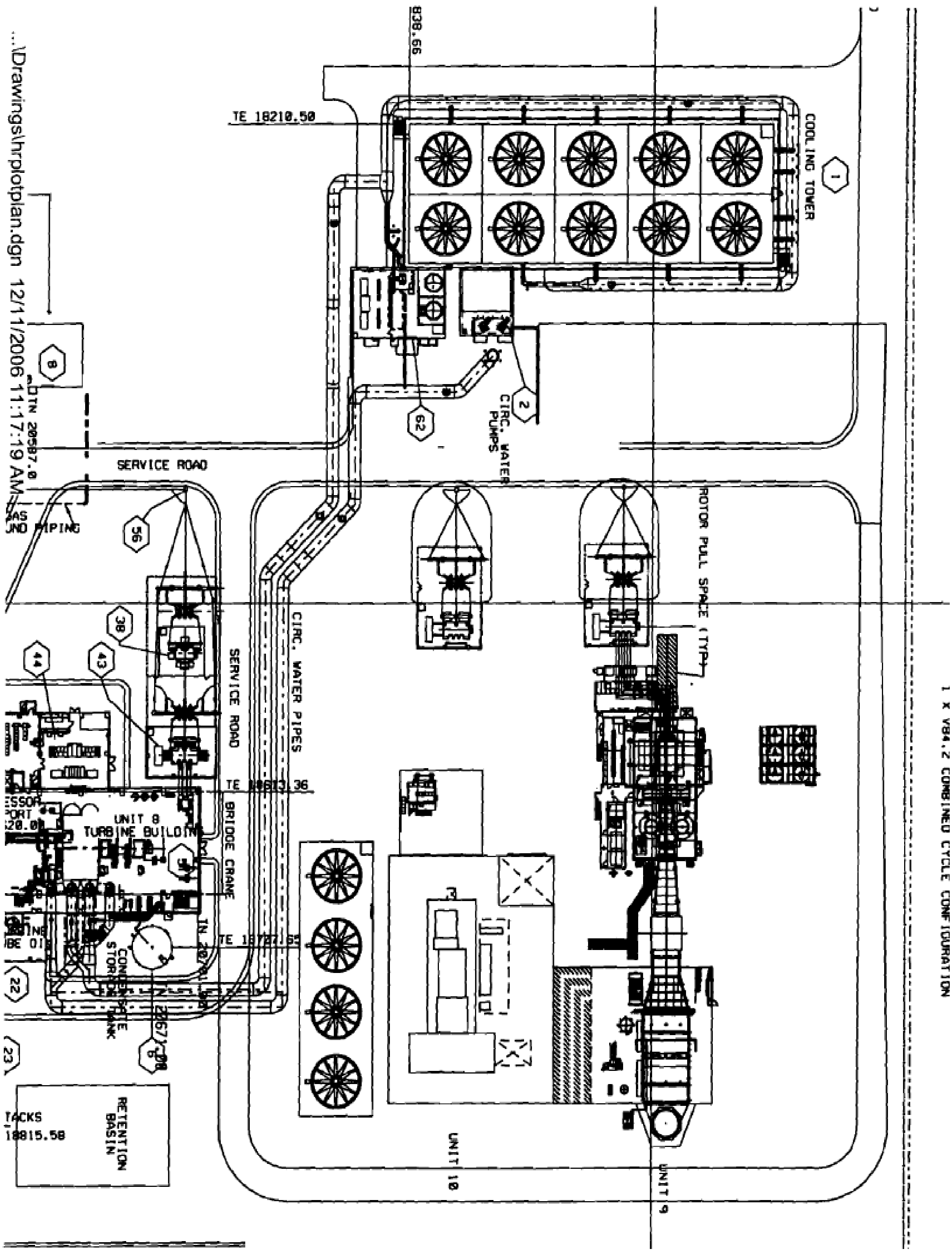
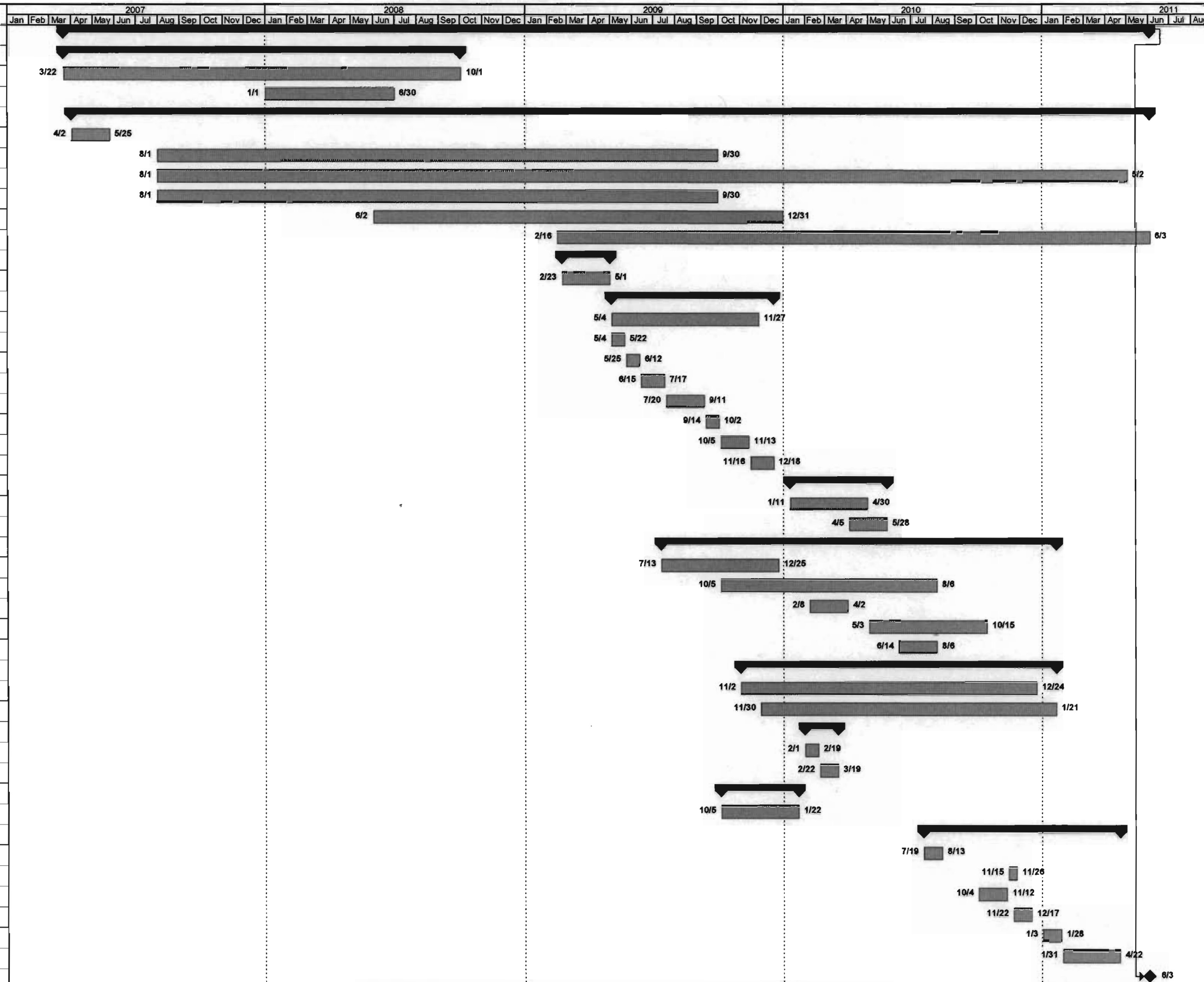


CONECTIV ENERGY PROJECT
1 X 1 COMBINED CYCLE
PROJECT SCHEDULE

ID	Task Name	Start	Finish
1	**DP&L PPA PROJECT SCHEDULE**		
2	**Licensing**		
3	Major Permit Approval	3/22	10/1
4	Site Development Approval	1/1	6/30
5	**Engineering**		
6	Soil Testing/Reporting	4/2	5/25
7	Architect/Engineering	8/1	9/30
8	Miscellaneous Project Support	8/1	5/2
9	Owners Engineering / Project Development	8/1	9/30
10	Equipment Procurement	6/2	12/31
11	Site Construction & Support	2/16	6/3
12	**Site Preparation**		
13	Clear/Rough Grade	2/23	5/1
14	**Major Foundations & Misc Concrete**		
15	Underground Piping and Trenching	5/4	11/27
16	Combustion Turbine	5/4	5/22
17	Diverter Damper (Future Conversion)	5/25	6/12
18	HRSG	6/15	7/17
19	Steam Turbine Generator	7/20	9/11
20	Demin Water Tank Foundation	9/14	10/2
21	Cooling Tower	10/5	11/13
22	HV Electrical Equipment (Including Poles)	11/16	12/18
23	**Structural Steel / Arch Packages**		
24	HRSG / STG BLGS	1/11	4/30
25	Architectural Packages	4/5	5/28
26	**Install & Erect Generating Equipment**		
27	Combustion Turbine	7/13	12/25
28	HRSG	10/5	8/6
29	Condenser	2/8	4/2
30	Steam Turbine	5/3	10/15
31	Cooling Tower	6/14	8/6
32	**BOP Mech / Elec**		
33	BOP Mechanical	11/2	12/24
34	BOP Electrical	11/30	1/21
35	**Install Transmission Lines and Structures**		
36	HV Gear and Relay Equipment	2/1	2/19
37	Areal transmission System Install	2/22	3/19
38	**Demin. Water Tank**		
39	Erect & Test Tank	10/5	1/22
40	**Commissioning Generating Equipment**		
41	CT Pre- Commissioning Activities	7/19	8/13
42	CT Commissioning Activities	11/15	11/26
43	STG Cold Commissioning Activities	10/4	11/12
44	Steam Blows	11/22	12/17
45	STG Hot Commissioning Activities	1/3	1/28
46	Acceptance Testing / Compliance Testing	1/31	4/22
47	**Commercial Operation**		6/3



Project: Hay Road 9 & 10
Date: Mon 12/18/06

Task | Split | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Split | Rolled Up Milestone | Rolled Up Progress | External Tasks | Project Summary | External Milestone | Deadline

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II.	**BASE BID PROPOSAL – Application Forms**
	m. Form M

Form M - Site Development Socio Economic

Describe Environmental Effects of Power Plant Construction and/or Operation on the following:

1) Visual Landscape and Visibility Impacts

The visual landscape surrounding the project site is dominated by industrial facilities including the City of Wilmington's Wastewater Treatment Plant, VFL-Headwater's sludge stabilization facility, Cherry Island Landfill, DuPont's Titanium Oxide plant, industrial warehouses, Amtrak's rail yard, and major transportation corridors, among others. As such, the visibility impacts of the new power plant, if any, should be minimal. Moreover, the proposed plant site is located immediately adjacent of the similar HRPC facilities.

2) Archaeological and Historical Sites

No archaeological or historical sites exist on or adjacent to the proposed project site. No sites of cultural resource value are located in the vicinity of the project site.

3) Landmarks and Sensitive Areas

No landmarks or sensitive areas exist on or adjacent to the proposed project site. Fox Point Park is located approximately one mile north of the site, and separated from the latter by DuPont's Titanium Oxide plant and other industrial facilities. As such, the proposed power plant should not be visible from this park.

4) Noise Impacts

The proposed power plant would be located more than 3,500 feet from the nearest residential areas located to the northwest. The plant site is separated from these residential areas by the Amtrak rail corridor, Amtrak rail yard, I-495, Governor Prince Boulevard (U.S. Route 13), and Hay Road, among others. The proposed plant site is located in, and surrounded by, industrially zoned lands, and the plant will comply with all applicable noise ordinances. No noise impacts are anticipated.

5) Transportation Impacts

The proposed plant site is strategically located east of I-495, and can be accessed via Hay Road from either of two nearby exits off of I-495. Access to the site will require no traffic through either residential areas or via roadways with unacceptable levels of service.

6) FAA Impacts

The proposed plant will have no impacts to air traffic. Although not required based on the proposed stack height, Conectiv Energy will submit the proper FAA notification package.

Form M - Site Development Socio Economic

7) Economic Development

During construction, total craft man hours will approach 400,000 with an additional 125,000 of non-craft or management hours. Secondary benefits include property and use tax revenues and increases and trickle down revenues for all area businesses.

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TABS	**TITLE**
II.	**BASE BID PROPOSAL – Application Forms**
	n. Form N – Complete with Attachments

Form N - Site Development Interconnection Arrangements

1) Please indicate if the proposed generator will interconnect with the DPL transmission or distribution system.

__X___ New Transmission Interconnection ______ Increase generating Capacity

2) Indicate the type of interconnection service that will be requested.

_______ Network Resource Interconnection Service __X___ Energy Resource Interconnection Service

3) Will the proposed generator interconnect with an existing substation / switchyard or require the construction of a new substation or switchyard?

___X___ Existing Substation or Switchyard ______ New Substation or Switchyard

4) Provide substation or switchyard number as used by the PJM ISO (PNODE ID from PJM LMP Bus Model).

8804 - Red Lion 230kV (180 MW)

5) Describe the location of the proposed point of interconnection, such as the name of an existing substation or switchyard, or the point on an existing transmission line, such as x-miles south of ABC Substation or halfway between ABC and XYZ substation. Provide the County name and the Section, Township and Range of the proposed point of interconnection. Include the interconnection voltage.
Attach a USGS-based map showing the proposed locations.

Point of interconnection of the combustion turbines shall be on the end of the transmission line providing service to Hay Road Unit 8. This line is 230kV and is injected at the Red Lion Substation via a 230/500 kV transformer, but this is anticipated to change with the reconfiguration of the Red Lion substation planned by Delmarva Power.

6) Describe the electric interconnection facilities that have been included in the bid price, including the cost, size, length and location of any transmission line and the cost, size and list of substation equipment for which the transmission customer (Bidder) will be responsible for building and owning.

Turbine generators will be connected to the existing 230kV line servicing Hay Road Units 5-8. Size of conductor should be 1590 kcmil 45/7 ACSR Lapwing to match existing. Length of the line is approximately 325 feet.
Cost is estimated at $900K.

Form N - Site Development Interconnection Arrangements

7) Please indicate if the proposed generator will require a new transmission interconnection or an expansion of an existing interconnection with the DPL system?

An expansion of an existing interconnection with the DPL system will be required.

8) DPL will assume no network upgrades are included in the Bidder proposal unless specified. If network upgrades are included, please indicate the total assumed capital costs for all transmission interconnection facilities

$ 0.00

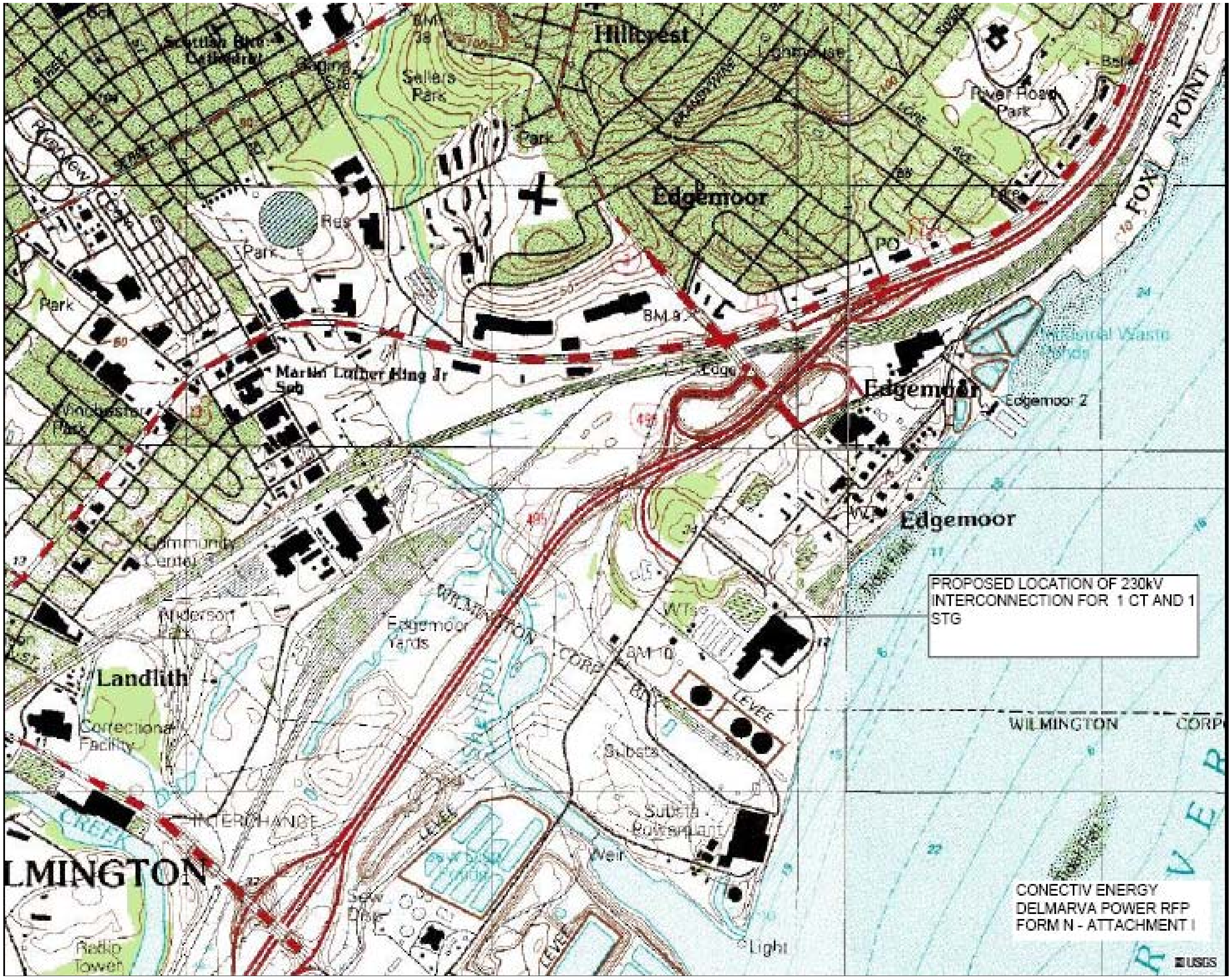
9) DPL will assume no network upgrades are included in the Bidder proposal unless specified. If network upgrades are included, describe the specific transmission elements to be upgraded and include a narrative description of the upgrade plan.

No network upgrades are included in the Bidder proposal.

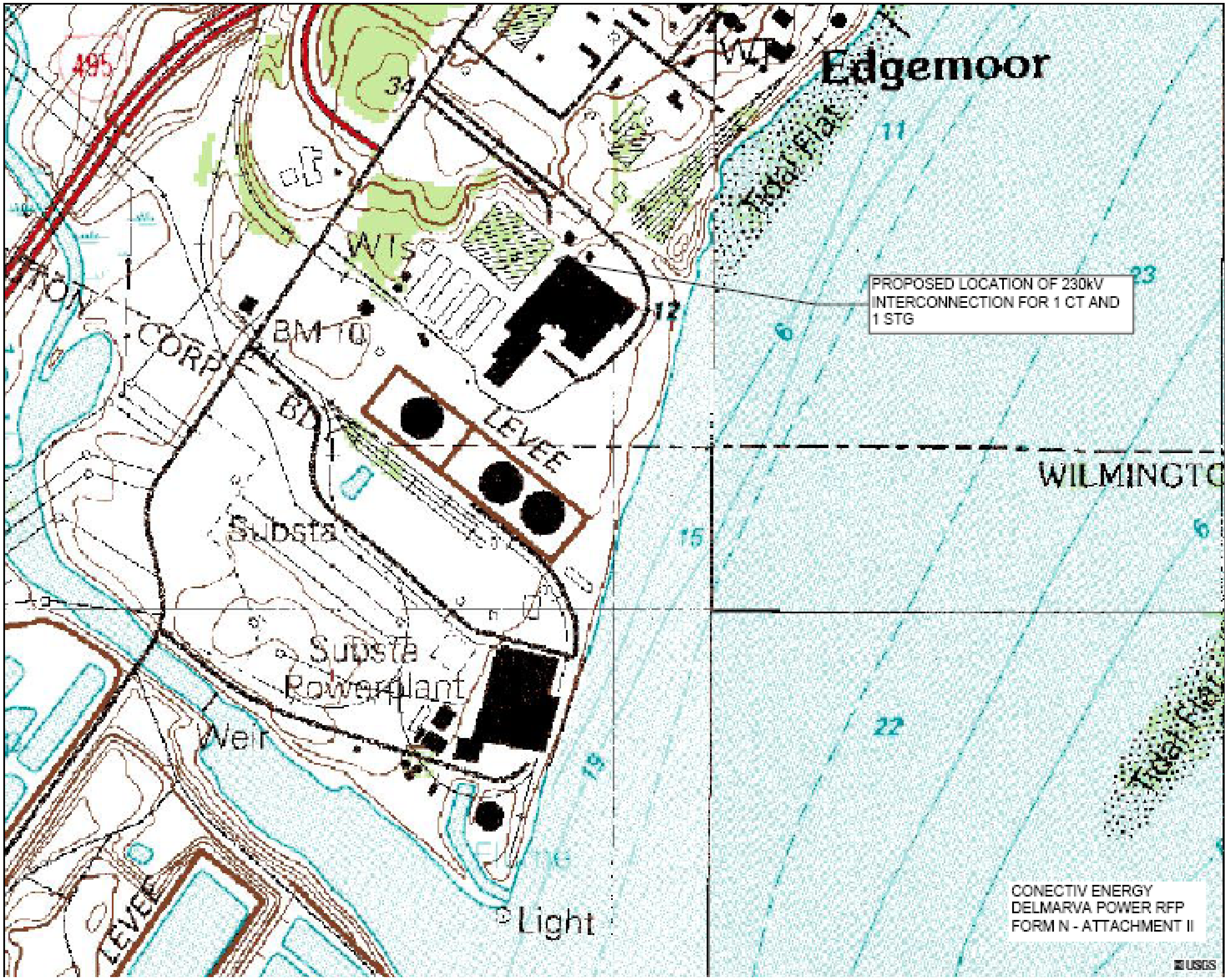
10) If available, provide a copy of bidder's preliminary transmission interconnection study.

Not Available

FORM N - ATTACHMENT I



FORM N - ATTACHMENT II



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TABS	TITLE

II. **BASE BID PROPOSAL – Application Forms**

o. Form O – Complete with Attachments

Form O - Financial Information

1) Bidder Legal Name: **Conectiv Energy Supply, Inc.**

2) Physical Address: **Conectiv Energy and Technology Center**
500 North Wakefield Dr., Newark, DE 19702

3) Financial/Credit Contact Person: Nate Wilson
Position Title: Vice President - Operations and Risk
Telephone: 302 451-5120
Fax: 302 451-5261
E-mail: nate.wilson@conectiv.com

4) Federal Tax Identification Number **23-1984748**

5) Bidder Dun & Bradstreet Identification Number **08-252-5226**

6) Bidder is (check all that apply)

a.	Corporation	**X**
b.	Partnership	
c.	Joint Venture	
d.	Sole Proprietorship	
e.	Limited Liability Company	
f.	Limited Liability Partnership	
g.	Other (attach description)	

7) Indicate if the bidder intends to use a guarantor. If yes, provide legal name of the guarantor.

Yes, CESI will use Pepco Holdings, Inc. as its parent guarantor

8) Guarantor's Dun & Bradstreet Identification Number: **10-589-5010**

9) Bidder Credit Rating Information: **CESI is not individually rated.**

	Issuer Rating	Senior Unsecured Rating	Short-Term Rating
S&P			
Moody's			
Fitch			

10) Provide rating reports from the respective agencies for prior 36 months.

CESI is not individually rate - no reports to attach.

Form O - Financial Information

11) Guarantor Credit Rating Information

	Issuer Rating	Senior Unsecured Rating	Short-Term Rating
S&P	**BBB**	**BBB -**	**A2**
Moody's	**Baa3**	**Baa 3**	**P3**
Fitch		**BBB -**	**F2**

12) Provide rating reports from the respective agencies for prior 36 months.
Please see the attached reports from S&P. The reports from both Moody's and Fitch are protected by them from reprinting or distribution but can be seen on their respective web sites or can be viewed in our offices.

13) If bidder is relying on guarantor for credit support, please describe the corporate relationship between bidder and guarantor. Also, provide a statement regarding the proposed guarantor's willingness to provide guarantee acceptable to DPL (see attachment to PPA).

CESI is a wholly owned subsidiary of Conectiv Energy Holding which is in turn a wholly subsidiary of Pepco Holdings (PHI). See attached letter.

14) Provide audited financial statements for the last three years for bidder and guarantor (if applicable). If audited financial statements are not available, provide un-audited financial statements with CFO attestation. If financial statements are consolidated, provide stand-alone financial statements with CFO attestation for bidder and guarantor.

CESI does not have audited financial statements. PHI's audited statements can be viewed and downloaded at its web site www.pepcoholdings.com.

Form O - Financial Information

15) For all related liquidity/credit lines for the bidder and/or guarantor (if applicable), list all credit lines and, for each credit line, provide the following information:

a. Type of facility (i.e. 364-revolver, 3-year revolver or bilateral loan), size, expiration date

PHI has a capacity of $700 million out of a $1.2 billion PHI corporate credit facility (the remaining $500 million is for the 3 utilities). The facility is for 5 years expiring May 16, 2011.

b. Issuing entity, obligor, guarantor, co-guarantor

PHI as a signor of the Agreement is the obligor.

c. How much of the facility can be drawn as cash and how much as letter of credit

$700 million is the maximum of a combination of cash drawn and letters of credit.

d. What is current availability and usage under the line Provide, historical, minimum, maximum, average for the last 24 months

Please see the attached table.

e. Indicate if this is a committed or uncommitted credit line

__X__ Committed _____Uncommitted

f. Does the credit line have a MAC clause? __X__ Yes _____No

g. Does the facility have a security interests or springing security interests? If yes, describe security interest and/or springing security interests

No

i. Estimated collateral requirements in the event of credit downgrade (below investment grade). Provide minimum, maximum and average information for the last 24 months.

There are no collateral requirements. Credit will always be available to PHI regardless of its credit rating, it will just be more expensive to borrow.

16) Demonstrate that consolidation under FIN 46 will not occur under your proposal. Provide supporting information sufficient to enable Delmarva to independently verify such conclusion.

Please see the attached conclusion of CESI.

17) Identify the primary financing sources for the construction phase of the project

Common Equity:	**20 - 50%**
Preferred Equity:	**0.00%**
Debt:	**50% - 80%**

18) For financing in the construction stage, provide funding source (new equity, equity contribution from guarantor/parent, etc.). If equity contribution from parent, provide funding source at the parent level (cash in hand, debt, new equity).

Parent funding would be provided through a mixture of current cash on hand, existing credit facilities, and routine equity issuance. Alternatively, CESI may utilize project financing which would result in the higher debt level.

Form O - Financial Information

19) Identify the primary financing sources for the permanent financing of the project

Common Equity:	**20 - 50%**
Preferred Equity:	**0.00%**
Debt:	**50 - 80%**

20) For the permanent financing, provide funding source (new equity, equity contribution from guarantor/parent, etc.). If equity contribution from parent, provide funding source at the parent level (cash in hand, debt, new equity).

Parent funding would be provided through a mixture of current cash on hand, existing credit facilities, and routine equity issuance. Alternatively, CESI may utilize project financing which would result in the higher debt level.

21) Attach pro-forma construction and operations worksheets in MS Excel format with formulas intact. Provide the balance sheet, income statement, and statement of cash flows for the life of the project.

Please see the attached pro-forma.

22) Provide a discussion of how this project and its financing may affect the credit metrics and credit ratings of the Bidder and/or its Parent / Credit Guarantor.

Given the level of funding required, we expect no material impact on the credit metrics or ratings of either PHI or its affiliates.

23) Provide a statement demonstrating reasonable ability to finance the proposed facility based on past experience. Include a financial plan identifying approach to obtaining capital from the sources identified above including a letter from a financial institution stating that the project as proposed in this RFP is financeable.

No outside sources of funding are anticipated at this time. PHI and CESI have a long history of successfully funding large-scale generation projects such as Hay Road and Bethlehem.

Form O - Financial Information

24) Identify and describe the source of required security at each stage of the project's life and provide plan for posting it. Include a demonstration of the ability to post the security.

The required security will be provided through a parent guarantee from PHI. Please see the response to question 15 above to demonstrate the ability of PHI.

FORM O- QUESTION 12
ATTACHMENT I

Provide rating reports from the respective agencies for prior 36 months.

- **S&P Rating Agency Reports for 2004, 2005, and 2006**

FORM O- QUESTION 12
ATTACHMENT I

Provide rating reports from the respective agencies for prior 36 months.

- **S&P Rating Agency Reports for 2004**

STANDARD & POOR'S RATINGSDIRECT

RESEARCH

PEPCO Holdings Inc.

Publication date: 28-Jan-2004
Credit Analyst: Michael Messer, New York (1) 212-438-1618

Corporate Credit Rating

BBB+/Stable/A-2

Business profile:
4
Financial policy:
Moderate
Debt maturities:
2004 $352 million
2005 $483 million
2006 $410 million
2007 $825 million
2008 $274 million
Bank lines/Liquid assets:
As of September 2003, the company's primary source of liquidity was a $1.1 billion credit facility divided betwe $550 million, 364-day facility and $550 million, three-year facility. The parent's borrowings are capped at $700 million and the remaining $400 million is available to the three operating utilities. As of Sept. 30, 2003, $270 mi in commercial paper and $49 million in LOCs were outstanding under the facility. Bank lines under the credit fa remain undrawn.
Total rated debt:
As of Sept. 30, 2003, the company had $6.7 billion in debt outstanding, including $5.1 billion in long-term debt, $303 million in nonrecourse construction revolvers, $270 million in commercial paper, $265 in current maturitie long-term debt, $258 million in short-term variable rate debt, $265 million in trust-preferred and redeemable preferred stock, $130 million in capital lease obligations, and $63 million in serial preferred stock.

Outstanding Rating(s)	
PEPCO Holdings Inc.	
Sr unsecd debt	
Local currency	BBB
CP	
Local currency	A-2
Conectiv	
Corporate Credit Rating	BBB+/Stable/NR
Sr unsecd debt	
Local currency	BBB
Potomac Electric Power Co.	
Corporate Credit Rating	BBB+/Stable/A-2
Sr unsecd debt	
Local currency	BBB
Sr secd debt	
Local currency	A-
CP	
Local currency	A-2
Pfd stk	
Local currency	BBB-
Atlantic City Electric Co.	
Corporate Credit Rating	BBB+/Stable/A-2

Sr unsecd debt	
Local currency	BBB
Sr secd debt	
Local currency	A-
CP	
Local currency	A-2
Pfd stk	
Local currency	BBB-
Delmarva Power & Light Co.	
Corporate Credit Rating	BBB+/Stable/A-2
Sr unsecd debt	
Local currency	BBB
Sr secd debt	
Local currency	A-
CP	
Local currency	A-2
Pfd stk	
Local currency	BBB-
Potomac Capital Investment Corp.	
Corporate Credit Rating	BBB/Stable/NR
Sr unsecd debt	
Local currency	BBB

Corporate Credit Rating History	
May 14, 2002	BBB+
July 26, 2002	BBB+/A-2

Company Contact
Mr. Anthony Kammerick, Vice President and Treasurer (1) 202-872-2056

Major Rating Factors

Strengths:

- The low operational risk of the company's transmission and distribution utilities;
- The stability of regulated business lines that are forecast to contribute the majority of the consolidated company's cash flow through 2006; and
- Superior service territories characterized by household income levels that are higher than national and regional averages, strong population growth, a high percent of residential and commercial customers, lo exposure to cyclical industrial demand, and strong forecasted growth in electricity consumption.

Weaknesses:

- A deleveraging strategy that entails significant execution risk;
- Rate caps in Maryland and the District of Columbia that require cost reductions at Potomac Electric Pow Co. and Delmarva Power & Light Co. to maintain historical operating margins;
- The business risks of Conectiv Energy Holdings' 3,400 MW merchant generation portfolio that introduce cash flow volatility; and
- Below-average liquidity.

Rationale

The ratings on PEPCO Holdings Inc. (PHI) and its subsidiaries are based on the consolidated business and financial risk profile of all of the company's regulated and unregulated operating units. The regulated businesse include Potomac Electric Power Co. (Pepco) and Conectiv, an intermediate holding company of Delmarva Pow Light Co. (DPL), Atlantic City Electric Co. (ACE), and Conectiv Energy Holdings (CEH).

In addition to PHI's regulated assets, the rating assesses the unregulated operations of Potomac Capital

Investment Corp. (PCI), a finance subsidiary with investments primarily in overseas energy leases, Pepco Ener Services Inc., which provides retail power and energy management services to customers in the Mid-Atlantic region, Pepcomm LLC, a telecommunications joint venture, and CEH, a nonregulated subsidiary of Conectiv, w portfolio of merchant generation assets in the PJM Interchange. As the sole supplier of provider-of-last-resort (POLR) service to DPL, as well as management's expectation that CEH will materially contribute to future debt repayment efforts, Standard & Poor's Ratings Services considers CEH to be a core business for PHI and, thus, consolidates this entity into the evaluation of PHI's overall business and financial position.

Washington, D.C.-based PHI had $6.7 billion in debt outstanding as of Sept. 30, 2003, including trust-preferred redeemable preferred stock and capital lease obligations.

On Nov. 24, 2003, Standard & Poor's affirmed its 'BBB+' long-term corporate credit ratings on PHI and its utility subsidiaries, and removed the ratings from CreditWatch with negative implications following the U.S. Bankrupto Court's approval of the transitional power agreement (TPA) settlement between Pepco and Mirant Corp.

Under the terms of the settlement, Pepco will continue to purchase from Mirant its standard offer service (SOS) power for Maryland and Washington, D.C. customers at prices that allow Pepco to earn margins that are two-th lower than under original contract terms.

Standard & Poor's business profiles are categorized from '1' (strong) to '10' (weak). PHI's '4' consolidated busir profile is due to the stability of PHI's transmission and distribution (T&D) businesses, the very strong markets ir service territories for some of the operating utilities, and the stable cash flow generated from regulated busines lines that are forecast to contribute more than 70% of cash flow. These strengths are offset by the risk associat with its 3,400 MW merchant generation portfolio (about half of which is hedged) and a somewhat less-supportiv regulatory environment in New Jersey, which disallowed $45 million of stranded costs and permits a longer-tha expected recovery period for approved deferred balances. Management continues to take positive steps to limi risks from the unregulated activities of CEH and PCI. These measures include discontinuing proprietary trading CEH, the hedging of 50% of CEH's POLR obligation with affiliate DPL, the hedging of its generation capacity, a well as the gradual liquidation of PCI's portfolio of financial assets.

Despite the overall strength of PHI's underlying utility businesses and the recent Mirant settlement agreement, is operationally weakened by the company's ongoing relationship with bankrupt Mirant. Although the settlemen positive to the extent that it removes ambiguity surrounding the status of the TPA contracts, operating margins SOS sales will now be lower, and Pepco remains exposed to the uncertainties of a bankrupt power supplier.

PHI will also be operating under extended rate caps for T&D services until 2006 in Maryland and Delaware and 2007 in Washington, D.C.

The 'BBB+' rating acknowledges that management's strategy of reducing $1 billion in debt for the next four yea subject to the realization of additional merger synergies, the ability of unregulated CEH to contribute meaningfu future cash flow, and the company's ability to continue to operate efficiently in light of rate freezes in Maryland a Washington, D.C. The renegotiated TPA settlement with Mirant will further reduce operating margins on sales t SOS customers by $60 million on a pretax basis.

For the next several years, Standard & Poor's expects funds from operations (FFO) to average total debt to be around 19% and adjusted FFO interest coverage to be about 3.6x. Although FFO to average total debt is weak the 'BBB+' rating category, interest coverage metrics remain in the category benchmarks. Standard & Poor's expects adjusted debt to total capital to decline over the next several years, from the current figure of 65%. Leverage ratios include trust-preferred and mandatorily redeemable preferred stock as debt.

Liquidity.

PHI's liquidity position is below average. As of September 2003, PHI's primary source of liquidity was a $1.1 bil credit facility divided between a $550 million, 364-day facility and $550 million, three-year facility. Despite this capacity, federal regulation may constrain PHI's future liquidity position because shareholder equity was only 2 above the 30% threshold required by the Public Utilities Holding Company Act (PUHCA) as of September 2003 based on PHI's unadjusted consolidated balance sheet debt. Borrowings by PHI are capped at $700 million an remaining $400 million is available to the three operating utilities. As of Sept. 30, 2003, $270 million in commer paper and $49 million in LOCs were outstanding under the facility. Bank lines under the credit facility remain undrawn. PHI had access to $781 million in undrawn capacity. PHI is estimated to have access to only $272 m in available credit before needing an SEC waiver to incur additional debt. Standard & Poor's believes that the S would waive PUHCA requirements in the short term, to allow PHI to access the capital markets or continue use its credit facility.

In general, PHI is forecast to generate positive discretionary cash flows between $300 million and $400 million annually, that will be needed to service upcoming debt payments of $352 million in 2004, $483 million in 2005, $410 million in 2006, and $825 million in 2007. PHI may issue both debt and equity to refinance these maturitie Flexibility is somewhat inhibited by low levels of discretionary capital spending and the absence of significant saleable assets. PHI is moderately exposed to ratings-related collateral calls. If PHI were downgraded below investment grade, it is estimated that PHI would require $338 million in additional cash.

Outlook

The stable outlook reflects Standard & Poor's expectation that PHI's regulated utilities will continue to generate sufficient free cash flow to implement management's deleveraging strategy. The ratings or outlook could chang debt repayment plans are delayed, management is unable to maintain operating margins at the regulated utiliti while subject to rate caps in Maryland, the District of Columbia, and Delaware, or nonregulated subsidiaries fail improve profitability while maintaining a prudent risk profile.

Rating Methodology

The ratings on PHI and its subsidiaries are based on the consolidated business and financial risk profile of all o company's regulated and unregulated operating units. Although PHI has indicated that it does not intend to pro material financial support to CEH, Standard & Poor's considers CEH to be a core business for PHI. This is due management's expectation that CEH will meaningfully contribute to future debt repayment efforts and given the subsidiary's role as the sole supplier of POLR service to DPL. Therefore, Standard & Poor's consolidates this e into the evaluation of PHI's overall business and financial position.

PHI's senior unsecured debt obligations are rated one notch lower than the corporate credit rating due to the structural subordination of the holding company debt.

Business Description

PHI is a diversified energy company with both regulated and unregulated transmission, distribution, and genera assets serving the District of Columbia, parts of Maryland, southern New Jersey, Delaware, and Virginia. The company was created from the August 2002 merger of Pepco and Conectiv, a holding company of DPL, ACE, a CEH.

In 1999, Pepco committed itself to becoming a pure T&D company by announcing its intention to sell substantia all of its generating assets. Pepco achieved this objective by selling all but 800 MW of its generating capacity to Mirant in 2000. The Conectiv merger increased the geographic scope of Pepco's T&D business by including DP and ACE customers in PHI's service territory, and adding about 3,400 MW of generation capacity through asse owned by CEH. CEH is an unregulated business unit that seeks to manage and optimize a portfolio of intermec load plants during peak demand periods.

PHI is also involved in the financial services industry through PCI, a finance subsidiary with investments primar overseas energy leases. Other nonregulated businesses include Pepco Energy Services, which provides retail power and energy management services to customers in the Mid-Atlantic region, and Pepcomm, a telecommunications joint venture.

In 2002, PHI's core T&D businesses generated 58% of revenues and contributed all of the company's operatin income. In the medium term, Standard & Poor's expects that regulated businesses will contribute 70% of opera income and 68% of PHI's operating cash flow.

Business Profile

PHI has a consolidated business profile score of '4' due to the stability of PHI's T&D businesses, strong market some of the operating utilities, and the stable cash flow generated from regulated business lines. These strengt are offset by the risk associated with CEH's merchant generation portfolio and a somewhat less-supportive regulatory environment in New Jersey. Management continues to take positive steps to limit the risks from the unregulated activities of CEH and PCI. These measures include discontinuing proprietary trading at CEH, the hedging of 50% of CEH's POLR obligation with affiliate DPL, the partial hedging of its generation capacity, as w as management's intention to discontinue further investment in PCI's portfolio of financial assets.

Regulation.

PHI benefits from regulatory diversification that mitigates the risk of an adverse regulatory decision in any jurisdiction. The company's regulated revenues are earned in Maryland (34%), New Jersey (27%), Delaware (2 Washington, D.C. (17%), and Virginia (1%).

Despite its regulatory diversity, all of PHI's major markets are concluding their transition to deregulation. In 199 the public service commissions (PSCs) of Maryland, Washington, D.C., Delaware, and New Jersey established multiyear transition period, during which PHI affiliates are required to operate under distribution rate caps in ret for being allowed to recover approved stranded costs. During the transition period, base rates include a tariff fo purchased-power costs based on prevailing average fuel prices and generation costs in 1999. In New Jersey, t transition period ended on July 31, 2003, whereas deregulation of the power supply market will not be fully implemented until 2004 in Maryland, 2005 in Washington, D.C., and 2006 in Delaware. No further deregulation initiatives are currently expected in these markets.

The distribution rate caps were originally scheduled to terminate with the conclusion of the transition periods in Maryland, Washington, D.C., and Delaware; however, the PSCs of these states extended the duration of the ra freezes by two years, as a condition for approving the Conectiv merger in 2002. Although rate caps for Pepco h been extended until 2006 in Maryland and 2007 in Washington, D.C., the utility will not be exposed to unexpect increases in purchased-power costs during this period. This is due to automatic energy pass-through adjustme that will be implemented in 2004 and 2005.

After July 2004, in Maryland, Pepco and DPL will solicit power supply bids for one-, two-, and three-year terms merchant power generators. The energy component of consumer rates will reflect a weighted average of the lo bids received by the utility. In the District of Columbia, the PSC has proposed that Pepco take bids for energy, capacity, and ancillary services in 50 MW blocks at seasonally differentiated prices. Although some details of th PSC's proposal have yet to be decided, the power acquisition process there will resemble the process already established in Maryland. In addition to being able to pass energy costs directly to end users, the utility will earn small margin on the power it delivers to its SOS customers in both Maryland and Washington, D.C. The Delawa PSC has yet to determine the procedures for energy procurement and pricing after the transition period ends in May 2006.

In New Jersey, ACE solicits power through 10-month and 34-month competitive bids. Energy tariffs for resident and commercial users reflect a blend of the lowest-priced bids and are passed through directly to consumers. Industrial users pay hourly spot prices for energy. The change in the power acquisition process occurred with th termination of the rate caps. Under the new market structure, ACE is no longer exposed to market-price fluctua and will no longer accrue deferred balances. Although the conclusion of the transition period is a positive event ACE, the New Jersey Board of Public Utilities' (NJBPU) recent decision to disallow $44.6 million in deferred balances that ACE incurred between 1999 and 2003 offsets some of the company's strengths. The approved recovery of $145 million in deferred balances was authorized for a 10-year period, rather than the four-year per originally contemplated when the Electric Discount and Energy Competition Act was passed in 1999.

The NJBPU has also approved the securitization of $152 million in stranded costs related to the B.L. England generating facility that ACE was unable to sell due to the bankruptcy of the plant's intended purchaser, NRG Energy Inc. The stranded cost securitization follows the $440 million securitization of stranded costs in 2002. Tl proceeds of both transactions will be used for debt reduction. ACE has also filed a rate case with the commissi requesting a $41.3 million annual increase in distribution rates, representing a 4.2% average increase over cur distribution charges.

Markets.

PHI benefits from some of the strongest service territories in the U.S. Overall population growth has averaged 6 in areas served by PHI utilities. The counties exhibiting the highest growth are served by DPL, which averaged 7.9% growth between 1996 and 2000. Although counties served by ACE fell below the average U.S. growth rat 6.1% over the same period, population growth in Southern New Jersey outpaced other areas in the Mid-Atlanti region. Growth in Pepco's region was a less robust 5.3%; however, slower growth is offset by median househol income in the District of Columbia and suburban Maryland that exceeds national averages by 30%. Pepco furth benefits from a customer base that has almost no exposure to heavy industry, given that residential, small commercial, and government users generate 98% of Pepco's revenue. Unemployment levels in the Washingtoı D.C. area are also below national averages due to the presence of the federal government as the region's large employer.

ACE and DPL are more sensitive to economic cycles than Pepco given higher unemployment levels and a high proportion of industrial customers. Although industry contributes less than 10% of ACE's revenues, 15% of DPL revenues and 23% of its delivered power derive from industrial users. The greater volatility of industrial demanc partially mitigated by growth in electricity consumption that is expected to exceed 6% across PHI's service territ through 2006.

Regulated operations.
PHI's regulated operations are above average, given the low risk associated with pure T&D businesses. Althou the overall operational profile of PHI's utilities remains strong, Standard & Poor's believes that Pepco's risks ha increased since Mirant's July 2003 bankruptcy announcement.

Pepco purchases 100% of its SOS obligation from Mirant through two TPA contracts that terminate in 2004 in Maryland and 2005 in Washington, D.C. At the time of the bankruptcy filing, Pepco purchased its power for SO customers at an average price of 3.4 cents per kWh that was substantially below prevailing market prices. As a result, Mirant announced its intention to renegotiate these agreements to obtain prices more consistent with cu market trends. Mirant reserved the right to reject the TPA agreements during bankruptcy in the event that a negotiated settlement was not reached between the parties. In October 2003, Mirant and Pepco entered into a settlement agreement that increased the cost of power under the TPAs to 4 cents per kWh and allowed Pepco submit a $105 million unsecured claim against the Mirant bankruptcy estate. Although the renegotiated settlem allows Pepco to earn a small positive margin on its SOS power, the agreement eliminated two-thirds of Pepco's power supply margin (about $60 million). The settlement is positive to the extent that it removes ambiguity surrounding the status of the TPA contracts; however, operating margins from SOS sales will now be lower, an Pepco remains exposed to the uncertainties of a bankrupt power supplier.

Despite the TPA renegotiation, Mirant has petitioned the U.S. Bankruptcy Court to reject two additional purchas power agreements (PPAs) with Pepco as part of its financial restructuring efforts. The PPAs under court review were sold to Mirant as part of Pepco's sale of its power-generating assets in 2001. Before these asset sales, Pe was obligated by the Public Utility Regulatory Policy Act to purchase high-cost power from designated qualifyin facilities like the Panda Brandywine power plant at Pepco's avoided power generation cost. As a condition of its asset sale, Pepco agreed to resell to Mirant the energy purchased under the Panda Brandywine and Ohio Edis PPAs under back-to-back agreements. On Dec. 23, 2003, the U.S. District Court rejected Mirant's petition to invalidate the PPA contracts stating that the court cannot overturn contracts on the theory that rates are too hig The court noted that the PPA rates were approved by the FERC and that the FERC bases its decision on matte of public interest, rather than on how contractual terms may affect the respective counterparties. The court's decision removes the threat that Pepco will pay higher power costs related to its nonutility generation contracts Although PHI was expected to have sufficient liquidity from internally generated cash flow to absorb any incremental power costs arising from the PPAs, the court's ruling improves PHI's credit position to the extent th PPA-related power costs will not pose a future drain on the consolidated company's near-term cash flow.

Nonregulated operations.
PHI's nonregulated operations consist of a 3,400 MW portfolio of intermediate dispatch merchant power assets owned by CEH. Of total generation owned by CEH, 66% is gas-fired, 20% is oil, 13% is coal, and less than 1% diesel fuel. Before Conectiv's merger with Pepco in 2002, CEH began construction of a 1,100 MW combined-cy plant in Bethlehem, Pa. that was completed on time and under budget. CEH cancelled the delivery of four combustion turbines from General Electric Co. in April 2003 due to high regional reserve margins and low powe prices that have impaired the value of these assets. The turbine cancellation resulted in a $31.1 million noncasl charge.

Despite poor market conditions, CEH is expected to contribute about 20% of PHI's future cash flow through 20(The merchant assets benefit from a natural hedge, given that CEH is the sole supplier of DPL's SOS obligation which totaled 14.1 million megawatt hours in 2002 and represents about 50% of CEH's installed capacity. CEH entered into a hedge transaction with an investment-grade counterparty that expires in May 2006 to mitigate 5C the volume and price risk arising under the DPL contract. Energy margin risks are mitigated through a "contract differences" that establishes a fixed cost of energy for 50% of CEH's full-requirements obligations to DPL. The hedge agreement also includes an energy price swap that CEH uses to lock in margins for 50% of the output o Edge Moor facility. Overall, the DPL contract and related hedge agreements partially mitigate the risks of CEH' merchant portfolio and stabilize income and cash flow of the subsidiary.

In addition to CEH's hedging arrangements, management has taken other positive steps to reduce the risk prof PHI's unregulated businesses. Most notably, management has ceased proprietary energy and gas trading activ in response to a $26.6 million one-day trading loss on gas futures in February 2003. Furthermore, PHI announc its intention not to increase the real estate, airplane and energy leveraged lease portfolio held by PCI.

Competitiveness.
PHI's regulated utilities have an above-average competitive position due to their role as the sole T&D provider i their respective service territories. Pepco residential rates in Maryland and Washington, D.C. are a low 7.38 ce per kilowatt hour (kWh) compared with the 9.20-cent average for the MAAC region. Nevertheless, the utility continues to be challenged by customer choice programs. Since customer choice shopping credits were introdu in July 2001, 16% of customers in Maryland and 12% of customers in Washington, D.C. (representing 35% of t utility's delivered load) have elected to source their energy from alternative suppliers that include Washington G Light Energy Services and Pepco affiliate Potomac Energy Services. The loss of SOS customers due to custon shopping programs is becoming less of a credit concern as a result of the TPA settlement agreement with Mira that no longer enables Pepco to earn abnormally high margins on the power procured for SOS customers.

Residential rates at ACE average 11.15 cents per kWh and are the highest in the MAAC region. Commercial a industrial rates average 9.0 and 6.5 cents per kWh, respectively, which is above average compared with other utilities rated by Standard & Poor's, but not atypical of utilities in New Jersey. DPL offers rates that are slightly l than state and national averages. Consumer shopping has not been widespread in either New Jersey or Delaw

Table 1

Potomac Electric Power Co. (Pepco) Customer Class Rates

Customer class	Number of customers	Revenue ($ mil.)	Sales (mil. kWh)	Average revenue per kWh (cents)	Washington, D.C. average (cents)	Maryland average (cents)	Pepco versus Washington, D.C. average (%)	Pepco versus Maryland average (%)	National average (cents)	P ve nat ave
Residential customers	645,478	565	7,659	7.4	7.4	7.7	100.0	96.5	8.5	
Commercial	72,151	828	18,488	4.5	4.6	6.9	97.0	64.6	7.9	
Industrial	0	0	0	0	2.3	3.9	0	0	5.9	
Total	717,629	1,393	26,147	5.3	4.8	6.2	112.2	86.4	7.4	

kWh -- Kilowatt hour.

Table 2

Conectiv Power Deliver Customer Class Rates

Customer Class	Number of customers	Revenue ($ mil.)	Sales (mil. kWh)	Average revenue per kWh (cents)	New Jersey average (cents)	Maryland average (cents)	Delaware average (cents)	Conectiv versus New Jersey average (%)	Conectiv versus Maryland average (%)	Conectiv versus Delaware average (%)	National average (cents)	Con ve nat ave
Residential customers	875,364	875	9,042	9.7	10.4	7.7	8.7	93.4	126.5	111.8	8.5	
Commercial	116,488	715	9,013	7.9	9.0	6.9	7.3	87.7	114.3	108.5	7.9	
Industrial	2,771	233	5,150	4.5	7.5	3.9	4.3	60.4	115.6	105.9	5.9	
Total	717,629	1,393	26,147	7.4	9.0	6.2	6.8	82.4	119.6	109.3	7.4	

*Including Atlantic City Electric Co. and Delmarva Power & Light Co. kWh -- Kilowatt hour.

Financial Profile

Financial Policy: Moderate

PHI has demonstrated a moderately aggressive financial policy based on management's willingness to finance $2.2 billion acquisition of Conectiv largely with debt. Fifty percent of the acquisition costs were funded with $70 million in debt, $400 million in the cash proceeds from the sale of PHI's generating assets, and the remaining $ billion was financed through a stock exchange. Almost two-thirds of the acquisition cost was related to goodwill totaling $1.4 billion. High leverage resulting from the acquisition continues to weaken the financial profile of the consolidated company and is a major focus of management's future financial strategy.

Due to financial statements that were not restated at the time of the Conectiv merger in August 2002, there are historical financial results that allow for meaningful comparisons with current operations. A full year of financial for PHI's consolidated operations since the merger were also unavailable. The consolidated company's 2002 financial performance therefore includes the contributions of Conectiv-owned subsidiaries only for the period fr August to December 2002. Operations for the first seven months of 2002 include only Pepco, PCI, and Potoma Energy Services.

Financial figures presented in this report reflect standard analytical adjustments concerning the debt equivalent operating leases and long-term purchased power obligations at ACE. Other adjustments reduce reported balan sheet debt to reflect repayment of debt from the proceeds of stranded cost securitization at ACE and cash hold and physical collateral that effectively defease a portion of the debt issued by PCI in connection with its leverag lease portfolio. Trust-preferred and mandatorily redeemable-preferred securities are classified as debt in this analysis.

Profitability and cash flow.

In 2002, substantially all of the consolidated company's operating margin came from its regulated operations. T trend continued for the first three quarters of 2003 due to losses at CEH. EBIT interest coverage adjusted for operating leases and imputed interest on purchased-power obligations was 2.5x in 2002. On a rolling 12-month basis, interest coverage has declined to 2x

During 2002, PHI generated $684.2 million of consolidated FFO, while FFO interest coverage was 3.6x. For the months ended Sept. 30, 2003, FFO interest coverage declined to 3.4x, which continues to be somewhat weak the ratings. The decline in interest coverage is due to the increase in leverage related to the Conectiv acquisitic third-quarter 2002. FFO to average total debt was about 12.9% during 2002, while for the 12-months ended in 30, 2003 the ratio rose to 15%, reflecting the additional cash flow contributed by ACE and DPL over the entire rolling 12-month period, relative to their five-month contribution to cash flows in 2002.

PHI's capital spending was about $500 million in 2002 and grew to $685 million over the last 12 months largely to increased costs related to the completion of the Conectiv Bethlehem project at CEH. Standard & Poor's fore that capital expenditures will average about $390 million through 2006. It is also expected that future cash flow also improve as a result of merger savings that are projected to save up to $100 million in operating expenses the next two years.

Capital structure and financial flexibility.

As of Sept. 30, 2003, consolidated debt leverage was about 65% and remains unchanged from 2002 year-end levels. This capitalization ratio includes $338 million of trust-preferred securities, which are now treated as debt accounting purposes but receive some equity treatment for analytical purposes. The company plans on reducir about $1 billion in debt over the next four years. About 50% of long-term debt is due by 2008.

Table 3

Pepco Holdings Inc. Competitors

Industry Sector: Diversified Energy

	--Last 12 months--			
(Mil. $)	**Pepco Holdings**	**Energy East Corp.**	**FirstEnergy Corp.**	**PSEG**
Rating	BBB+/Stable/A-2	BBB+/Negative/A-2	BBB-/Stable/--	BBB/Stable/--
Sales	7,330.1	4,725.7	12,489.3	11,117.0
Net income from cont. oper.	227.7	241.6	347.1	939.0
Funds from oper. (FFO)	853.1	618.0	1,686.7	1,380.0

Capital expenditures	684.1	209.0	858.7	1,565.0
Total debt	6,552.1	4,725.7	12,857.1	12,465.0
Preferred stock	63.2	459.8	0.0	80.0
Common equity	3,054.6	2,516.3	8,111.4	6,279.0
Total capital	9,669.9	7,701.8	20,968.5	18,824.0
Ratios				
Adj. EBIT interest coverage (x)	2.0	2.1	1.9	3.3
Adj. FFO interest coverage (x)	3.4	3.2	3.1	3.5
Adj. FFO/avg. total debt (%)	15.2	15.0	12.1	12.0
Net cash flow/capital expenditures (%)	99.2	183.2	145.1	57.0
Adj. total debt/capital (%)	64.5	57.3	61.3	66.8
Return on common equity (%)	6.5	8.4	4.6	14.2
Common dividend payout (%)	74.2	46.8	127.0	52.8

Table 4

Pepco Holdings Inc. Financial Summary

Industry Sector: Diversified Energy	
	--Fiscal year ended Dec. 31--
Rating history	BBB+/Stable/A-2
	2002
(Mil. $)	
Sales	4,323.8
Net income from cont. oper.	242.2
Funds from oper. (FFO)	684.2
Capital expenditures	493.2
Total debt	6,563.1
Preferred stock	63.2
Common equity	2,995.8
Total capital	9,622.1
Ratios	
Adj. EBIT interest coverage (x)	2.5
Adj. FFO interest coverage (x)	3.6
Adj. FFO/avg. total debt (%)	12.3
Net cash flow/capital expenditures (%)	111.3
Adj. total debt/capital (%)	64.9
Return on common equity (%)	7.0
Common dividend payout (%)	51.8

FORM O- QUESTION 12
ATTACHMENT I

Provide rating reports from the respective agencies for prior 36 months.

- **S&P Rating Agency Reports for 2005**

STANDARD & POOR'S RATINGSDIRECT

RESEARCH

PEPCO Holdings Inc.

Publication date: 23-Jun-2005
Primary Credit Analyst: Michael Messer, New York (1) 212-438-1618; michael_messer@standardandpoors.com

Corporate Credit Rating	
	BBB+/Negative/A-2

Financial policy:
Intermediate
Debt maturities:
2005: $510.9 million
2006: $536.9 million
2007: $854.9 million
2008: $305.3 million
2009: $82.2 million
Bank lines/Liquid assets:
Regulated utilities are individually limited to a maximum of $300 million and in the aggregate to $500 million under the credit facilities.
Total rated debt:
As of March 31, 2005, the company had $5.8 billion in debt, including $551 million of securitized transition bonds at Atlantic City Electric Co. and capital lease obligations.

Outstanding Rating(s)	
PEPCO Holdings Inc.	
Sr unsecd debt	
Local currency	BBB
CP	
Local currency	A-2
Conectiv	
Sr unsecd debt	
Local currency	NR
Potomac Electric Power Co.	
Corporate Credit Rating	BBB+/Negative/A-2
Sr unsecd debt	
Local currency	BBB
Sr secd debt	
Local currency	A-
CP	
Local currency	A-2
Pfd stk	
Local currency	BBB-
Atlantic City Electric Co.	
Corporate Credit Rating	BBB+/Negative/A-2
Sr unsecd debt	
Local currency	BBB
Sr secd debt	
Local currency	A-
CP	
Local currency	A-2
Pfd stk	

Local currency	BBB-
Delmarva Power & Light Co.	
Corporate Credit Rating	BBB+/Negative/A-2
Sr unsecd debt	
Local currency	BBB
Sr secd debt	
Local currency	A-
CP	
Local currency	A-2
Pfd stk	
Local currency	BBB-
Potomac Capital Investment Corp.	
Corporate Credit Rating	BBB/Negative/NR
Sr unsecd debt	
Local currency	BBB

Corporate Credit Rating History	
May 14, 2002	BBB+/A-2
July 26, 2002	A-2

Major Rating Factors

Strengths:
- Stable cash flow generated by PHI's regulated transmission and distribution businesses;
- Low operating risk at regulated utilities; and
- Monopoly transmission provider in above-average service territories.

Weaknesses:
- High leverage and weak financial metrics;
- Rate caps in major utility jurisdictions could pressure operating margins and cash flow through 2007;
- Increased business risk related to unregulated electricity wholesale and retail operations; and
- Unresolved litigation with Mirant Corp.

Rationale

Standard & Poor's Ratings Services' ratings on Pepco Holdings Inc. (PHI) reflect the stable cash flows and low business risk of PHI's electric transmission and distribution (T&D) businesses. The rating balances the credit strength of PHI's regulated utilities against the higher business risk of the company's unregulated wholesale and retail electricity operations, a high debt burden and financial metrics that Standard & Poor's expects will remain weak for the rating over the next two years.

In 2004, funds from operations (FFO) to total debt (adjusted for operating leases, securitized debt and contingent liabilities), was about 16% and is expected to remain at this level through 2005. The ratio of debt to total capital was also high for the rating at 59%. Standard & Poor's expects these relatively weak financial metrics to improve in 2006 and 2007 as PHI concludes a $1.3 billion debt-reduction plan that began in 2003. The expiration of rate freezes in Maryland, Delaware, and the District of Columbia beginning in 2006 should support PHI's debt-reduction plans after 2005 by allowing the utilities to request rate increases.

PHI's business profile is satisfactory. Regulated utility operations contributed about 70% of PHI's cash flow in 2004 and should remain at this level for the foreseeable future. Growing energy demand from desirable residential and commercial customers, the strong economic performance of PHI's service areas, and the ability to pass through wholesale power costs to ratepayers without a rate case support cash flow stability. Nonetheless, PHI's utilities will remain under pressure to reduce operating expenses during the rate freeze period to generate free cash needed for debt reduction. The stability of PHI's regulated cash flows is tempered by more volatile unregulated wholesale and retail power marketing businesses. An output hedging agreement at Conectiv Energy Holding (CEH), the completion of the Conectiv Bethlehem power project and a standard-offer service (SOS) contract with Delmarva Power & Light Co. (DPL) improve the competitiveness of PHI's wholesale power marketing business in the PJM market. In recent years, PHI has reduced the risk profile of its unregulated financial services operations by selling nonenergy related investments held by Potomac Capital Investment Corp. (PCI), but future cash flow contributions by PCI may decline as the result of a pending IRS decision on the tax deductibility of cross-border leasing transactions.

Short-term credit factors

PHI's short term rating is 'A-2' and reflects Standard & Poor's expectation that PHI will meet debt reduction targets for 2005 and retain significant available capacity under its credit facilities to meet its liquidity requirements and any cash payments resulting from a negative court decision in PHI's litigation with Mirant Corp. This litigation may expose PHI subsidiary Potomac Electric Power Co. (Pepco) to $150 million in cash payments in 2005 and $68 million in higher power costs. Standard & Poor's bases these estimates on the assumption that PHI must repay Mirant for disputed power costs at the earliest possible petition date and assumes that PHI will not recover these amounts as an unsecured creditor to Mirant's bankruptcy estate. Although regulators may allow some cost recovery from ratepayers, Standard & Poor's expects that regulatory recovery would lag cash expenditures and result in PHI missing its debt-reduction targets for the year. PHI believes that if Mirant wins its litigation, PHI will become an unsecured creditor to the Mirant bankruptcy estate and potentially recover sufficient amounts to mitigate the cash flow impact of any adverse court decision.

Absent any Mirant-related payments, Standard & Poor's expects PHI to generate positive discretionary cash flow in 2005. Standard & Poor's free cash flow estimate assumes no increase over the $735 million cash from operations generated in 2004, lower capital spending in 2005 due to the completion of the Conectiv Bethlehem plant, and no significant increase in dividend payments.

Outlook

The negative outlook reflects Standard & Poor's expectation that free cash flow will be under pressure until rate caps are lifted. Standard & Poor's could lower ratings if PHI fails to generate positive free cash flow in 2005, significantly delays debt-retirement plans, or if management is unable to maintain operating margins at the regulated utilities during the rate-freeze period. Furthermore, Standard & Poor's could lower ratings if a negative ruling in the Mirant lawsuit requires sizable upfront cash payments. Standard & Poor's could revise the outlook to stable, when PHI has substantially completed its debt reduction and financial metrics have improved to levels that are more appropriate for the rating.

Business Description

PHI is a diversified energy company with both regulated and unregulated T&D and generation assets serving the District of Columbia, Maryland, southern New Jersey, Delaware, and small parts of Virginia. Regulated utilities owned by PHI include Pepco, DPL, and Atlantic City Electric Co. (ACE). Unregulated businesses are primarily represented by CEH, which owns and operates about 3,698 MW of generating capacity in the Pennsylvania-Jersey-Maryland Interconnection. Other unregulated businesses include Pepco Energy Services (PES), one of the largest sellers of retail electricity and natural gas services in the mid-Atlantic region, and PCI, which manages a portfolio of energy leveraged leases in Europe and Australia.

Rating Methodology

The ratings on PHI and its subsidiaries are based on the consolidated business and financial risk profile of all of the company's regulated and unregulated operating units. PHI's senior unsecured debt obligations are rated one notch lower than its corporate credit rating due to the structural subordination of holding company debt to the secured debt issued at PHI's utilities.

Business Profile

PHI's business profile is satisfactory. The company's exposure to volatile wholesale and retail energy marketing businesses weaken PHI's business profile relative to other diversified energy companies that are predominantly involved in T&D activities. Peer companies with similar business lines and similar risk profiles include Northeast Utilities and, to a lesser extent, TXU Corp. and Energy East Corp.

Regulation

PHI's T&D utilities benefit from strong regulatory environments. Regulatory diversification mitigates the risk that an adverse regulatory decision in any one jurisdiction will unduly impair PHI's consolidated financial performance. The approximate proportion of the company's regulated sales are Maryland (38%), the District of Columbia (22%), Delaware (20%), New Jersey (19%), and Virginia (1%).

Most of the states served by PHI have completed the process of transitioning to a fully deregulated wholesale electricity market. New Jersey completed its transition in 2003, followed by Maryland in 2004 and the District of Columbia in 2005. The transition period in Delaware is scheduled to conclude in 2006, when Standard & Poor's expects the Delaware Public Service Commission to adopt a regulatory framework that is similar to the auction mechanism implemented in neighboring states.

As a result of wholesale electricity deregulation, all of PHI's utilities elected to sell the majority of their power generating assets and focus on the lower-risk T&D segment of the power business, and retain the SOS obligation to procure power supplies on behalf of customers that do not choose a retail power supplier. The utilities procure power through an auction process and end users pay a weighted-average power price based on the lowest bids accepted by the utility. Under this arrangement, commodity costs are automatically passed through to ratepayers, assuring the utilities of full cost recovery for power supplies and making it unnecessary to finance commodity-related regulatory assets while awaiting the outcome of a rate case. As a result, all of PHI's utilities should generate higher future cash flows due to the fuel pass-through mechanism in its various jurisdictions.

The Maryland and District of Columbia public utility commissions allow Pepco and DPL to earn a small margin on the energy delivered to SOS customers. Although Standard & Poor's does not expect these margins to be key cash flow drivers, the additional margins earned on SOS customers will help temper the effect of rate freezes that will remain until 2006 in Maryland and Delaware and 2007 in the District of Columbia. Standard & Poor's estimates that Pepco could earn as much as $40 million in additional cash flow as a result of the SOS margins. However, the actual cash contribution will vary due to changes in Pepco's customer mix and may decline if more customers select third-party power suppliers. ACE no longer operates under rate caps and in 2003 petitioned the New Jersey Bureau of Public Utilities (NJBPU) for increased base rates to recover costs incurred during the market transition period. Under an April 2005 settlement with the NJBPU, base rates will not be increased. However the utility will be allowed to recover $116.8 million in deferred restructuring charges over the next four years. This outcome is consistent with Standard & Poor's expectations and was already factored into ACE's and PHI's current ratings.

Markets

PHI serves some of the strongest markets in the U.S. On average, Standard & Poor's expects power deliveries among the three utilities to increase by 6.3% through 2007 as compared with a 7.4% average increase nationwide over the same period. Although overall growth may lag national averages, PHI benefits from service areas that are more affluent and are more economically stable than other areas of the U.S. In particular, Pepco enjoys a service territory that has household income levels that are about 30% higher than national averages and has almost no exposure to the often-volatile energy demand of heavy industrial customers. Unemployment in the District of Columbia region is also below national averages due to the presence of the federal government as the region's largest employer.

ACE and DPL are more sensitive to economic cycles than Pepco due to higher unemployment levels and a higher proportion of industrial customers. Although industrial customers contribute less than 10% of ACE's revenues, in DPL's service territory, industrial users account for 15% of revenues and 23% of delivered power volumes. Overall, Standard & Poor's believes that PHI's utilities have an appropriately diversified customer base that is capable of absorbing any rate increases that may result from escalating power costs in their respective service areas.

Regulated operations

Operational risk associated with T&D activities is low and supports PHI's current ratings. Reliability statistics at Pepco, DPL, and ACE are generally consistent with the outage rates of other similar utilities. In 2003, the extended outages caused by Hurricane Isabel focused media attention on the disaster-response capabilities of Pepco and, to a lesser extent, DPL. Management is taking steps to improve and coordinate disaster-planning efforts with relevant community stakeholders and has increased spending on vegetation-management initiatives and on integrating existing computer monitoring systems to improve disaster response times. Major reliability initiatives at ACE and DPL will be addressed in 2005 and 2006 through transmission construction programs aimed at reducing congestion on the Delmarva peninsula and at increasing transmission capacity into southern New Jersey after the closure of the BL England generating facility in 2007.

In general, operational risk at Pepco has decreased with the expiration of Transitional Power Agreements with Mirant Corp. With the expiration of these contracts, Pepco is no longer exposed to supply disruption risks related to Mirant's continuing bankruptcy. As a result of the wholesale electricity auctions that are currently in place in New Jersey, Maryland, and the District of Columbia, each of the utilities benefits from a more diversified base of power suppliers and is better protected from a supplier default by regulatory provisions that allow other market participants to quickly assume any unsatisfied load obligations that arise from a bankruptcy. DPL's current supply requirements will continue to be met through a contract with its unregulated affiliate CEH until 2006, when Standard & Poor's expects a similar wholesale auction arrangement to be implemented.

Unregulated operations

PHI's unregulated activities increase the business risk of the consolidated entity. PHI's primary unregulated business is CEH, which owns a portfolio of merchant power generating assets in the PJM Interconnection. The 3,698 MW portfolio is comprised of 9% base load coal capacity, 73% intermediate dispatch gas-fired facilities, and 18% peaking resources. CEH's strategy is to capitalize on the operational flexibility of its generating assets to sell power into transmission-constrained portions of the PJM East market during periods of rising prices. In 2004, CEH was able to earn positive margins despite weak market conditions due to the completion of the Conectiv Bethlehem power facility. The Bethlehem facility can respond more quickly to changing market conditions than typical gas- and oil-fired combined-cycle facilities in the region, due to shorter minimum run time and ramp-up requirements, and its ability to dispatch more often than its competitors. This allows CEH to be more selective in its sales commitments and to restrict its operations to only those periods that are most profitable.

Although the completion of the Bethlehem project has improved the profitability and competitive position of CEH in 2004, wholesale operations continue to introduce cash flow volatility into PHI's consolidated financial profile. CEH's market exposure is partially mitigated by a contract with DPL to provide 100% of the utility's default service obligation through 2006, representing about 50% of CEH's installed capacity. CEH currently has a hedging arrangement with a third party through 2006 that partly reduces CEH's remaining market exposure. After current hedges expire in 2006, CEH may be challenged to generate the roughly $40 per megawatt-hour (MWh) gross margins earned in 2004. CEH expects to obtain gross margins of between $36 per MWh and $48 per MWh in 2005 and 2006, and Standard & Poor's estimates that CEH will contribute about 15% of PHI's consolidated cash flow through 2008.

Other unregulated businesses include retail energy provider, PES and PCI. Standard & Poor's views retail energy marketing as somewhat less risky than the wholesale activities of CEH. However, both of these businesses increase the consolidated liquidity requirements of PHI and generate modest margins relative to their risk. Standard & Poor's expects the risk profile of PES to increase in the future as PHI expands its retail energy operations with the expansion of the PJM region. Any growth in the number of longer-dated, fixed-price retail contracts at PES will also require additional liquidity to support energy payables and collateral obligations. Currently, PHI has sufficient unused capacity in its credit facility to adequately support these obligations at both CEH and PES.

The risk profile of PCI has improved in 2004, with the complete sale of nonenergy-related assets and PHI's intention not to expand PCI's investment activities. Although PCI does generate cash flow through tax credits on a portfolio of highly collateralized, cross-border power generating assets, up to $175 million of these tax credits have become the subject of an IRS audit investigation. An adverse decision by the IRS could negate the benefit of PCI to its parent, and could expose PHI to unexpected cash payments that could derail debt-reduction efforts through 2007. Although an IRS decision is possible before 2007, any IRS audit decision is unlikely to materially affect PHI's financial profile in the near term due to the protracted appeals process that Standard & Poor's has observed in other similar cases.

Competitiveness

PHI's regulated utilities have an above-average competitive position due to their role as the sole T&D provider in their respective service territories. In 2003, Pepco's residential rates in Maryland and the District of Columbia were $70.68 per MWh as compared with the $94.4 per MWh average for the MAAC region. Residential rates at ACE averaged $112.14 per MWh and are among the highest in the MAAC region. Commercial and industrial rates at ACE average $88.7 per MWh and 63.93 per MWh, respectively, which is above average compared with other utilities rated by Standard & Poor's, but not atypical of utilities in New Jersey. DPL offers rates that are slightly lower than state and national averages.

Consumer shopping for retail electricity is significant throughout PHI's service areas. In 2004, customer choice programs represented about 32% of total load in the District of Columbia, 28% in Maryland, and 22% in New Jersey. Although higher customer shopping results in lower SOS margins in Maryland and the District of Columbia, the majority of PHI's utility revenues are generated through "wires" charges for which there is no meaningful competition.

Table 1

Pepco Holdings Inc. -- Cost and Rates Peer Analysis

$/MWh

Company	Residential rate	Commercial rate	Industrial rate
Atlantic City Electric Co.	112.1	88.7	63.93
Delmarva Power & Light Co.	83.1	70.58	28.28
Potomac Electric Power Co.	70.68	49.56	13.84
Mid-Atlantic Area Council average	94.4	72.98	55.43
Standard & Poor's average	83.94	76.55	44.42

MWh -- Megawatt hour. Source: Platt's Powerdat database.

Management

Standard & Poor's believes that PHI's management team has become more risk averse in recent years due to the cessation of proprietary trading at CEH, the sale of nonenergy-related assets from PCI's investment portfolio, and the sale of Starpower, a telecommunications joint venture in December 2004. Standard & Poor's expects PHI to retain its current mix of businesses over the next three years and believes that business risks could decline in future years as the result of management's ongoing risk-reduction efforts. Management continues to demonstrate its commitment to credit quality, as evidenced by its continuing execution of its debt-reduction plan and the $275 million equity issuance in 2004 that was used to support debt reduction objectives.

Financial Profile

Accounting

PHI reports its financial statements in accordance with U.S. GAAP. In addition to receiving an unqualified audit opinion, a review of PHI's internal control procedures under Section 404 of the Sarbannes-Oxley Act did not find any material weaknesses in 2004.

Important accounting principles that effect PHI's financial statements are SFAS 71 (Accounting for Regulatory Assets and Liabilities) and SFAS 133 (Accounting for Derivative Instruments and Hedging Activities). As of Dec. 31, 2004, PHI had $1.3 billion of regulatory assets accrued on the balance sheet versus $391.9 million in regulatory liabilities. About 66% of these regulatory assets represent stranded costs that PHI has already recovered through the issuance of transition bonds by Atlantic City Electric Transition Funding LLC (ACE Funding). Of the remaining $447.7 million regulatory asset balance, a recent settlement with the NJBPU has approved the recovery of $116 million in deferred-energy supply costs to be recovered over the next four years. As a result of both the securitized debt issuance and the NJBPU decision, a maximum of 25% of PHI's net regulatory asset balance on Dec. 31, 2004 could be at risk for a disallowance, which Standard & Poor's deems as unlikely.

PHI uses derivative financial instruments to hedge its interest rate exposure and to hedge cash flows related to commodity transactions entered into by CEH and PES. Market gains and losses on cash flow hedges are recorded in other comprehensive income and reclassified into earnings when a transaction settles. Derivatives that qualify as fair-value hedges are marked-to-market and reflected in earnings each quarter. For 2004, PHI recorded a net reduction in other comprehensive income of $47.9 million related to commodity contracts and interest rate treasury locks designated as cash flow hedges. Of this amount, PHI expects to realize $2.1 million in additional expense in 2005 related to the settlement of hedged transactions. In 2004, $6 million in expense was realized due to cash flow hedge ineffectiveness. However, these amounts were offset by increases in fair value hedges that contributed $21.4 million to PHI's pretax income.

Standard & Poor's makes a number of financial adjustments when evaluating PHI's financial ratios to reflect about $551.4 million in securitized debt issued by ACE, and about $700 million in collateralized debt related to PCI lease equity contributions. Because debt service for the securitized stranded costs at ACE are collected through a nonbypassable charge paid by all utility customers, interest and amortization on the securitized debt is subtracted from gross revenues, reported interest expense, and reported amortization amounts. Balance-sheet debt is also reduced by about $1.2 billion to reflect the collateral defeasance of these debt obligations.

The reduction in balance-sheet debt is partially offset by imputed off-balance-sheet obligations related to operating leases and nonutility generation purchased-power obligations at Pepco. Although Standard & Poor's does not attribute a debt equivalent to purchased-power obligations arising under the Basic Generation Service auctions in New Jersey or the SOS auctions in Maryland and the District of Columbia, Standard & Poor's does attribute about $132 million in imputed debt related to above-market power costs that PHI may incur as a result of a negative judgement in its litigation with Mirant. This amount represents a contingent liability that Standard & Poor's believes may become a fixed obligation of PHI over the next several years. If a favorable, final legal decision is made, Standard & Poor's would no longer impute any Mirant-related debt to PHI's financial metrics.

As a result of these adjustments, FFO to average total debt was increased from 14.7% to about 16% and FFO to interest ratios increased from 3x to 3.9x in 2004. Similarly, leverage ratios are more favorable under Standard & Poor's methodology. As of December 2004, Standard & Poor's estimates that unadjusted debt to total capital was about 64.4% and adjusted debt to total capital is estimated to be 59%.

Profitability and cash flow

In 2004, about 70% of PHI's cash flow was generated by regulated operations. Adjusted interest coverage ratios remain adequate for the current rating at 3.9x for fiscal year 2004, however, adjusted FFO to total debt ratios of 16% remain weak for a 'BBB+'. Notwithstanding somewhat weak cash flow ratios, cash from operations increased from $661.4 million in 2003 to $734.6 million in 2004 due to lower working-capital requirements. In 2004, PHI generated modest positive discretionary cash flow to support debt reduction efforts.

Standard & Poor's expects improving financial performance through 2007 as PHI continues to meet debt-reduction targets. FFO is anticipated to improve by about 10% over the next two years as rate freezes end in Maryland and the District of Columbia and deferred energy costs are recovered in New Jersey. Standard & Poor's expects capital spending to average about $420 million annually over the next five years and does not expect significant increases in dividends. Based on these assumptions, PHI should be able to generate at least $100 million in discretionary cash flow annually to meet a $1 billion debt reduction target by 2007. Nonetheless, PHI remains susceptible to any events that require large cash payments before 2007 and ratings remain contingent on PHI's ability to continue debt reduction.

Capital structure and financial flexibility

As of Dec. 31, 2004, adjusted debt to total capital was about 59.1%, representing a significant improvement over the 63.3% ratio observed in 2003. Improvements in leverage reflect PHI's reduction of $480 million in debt and preferred stock in 2004. Deleveraging was significantly facilitated by at $308 million equity issuance (including PHI's dividend reinvestment program). Upcoming debt maturities are moderate and Standard & Poor's expects debt due at PHI's utility subsidiaries to be refinanced rather than retired.

PHI's financial flexibility is adequate. The company maintains strong access to debt and equity markets.

Furthermore, the company typically retains substantial unused capacity under its $1.2 billion credit facilities to meet any unforeseen obligations. The liquidity requirements of CEH and PES are currently manageable given the capacity of PHI's credit facilities.

Table 2

Pepco Holdings Inc. -- Competitors

	--Last 12 months as of Dec. 31, 2004--			
	Pepco Holdings Inc.	**Energy East Corp.**	**Northeast Utilities**	**TXU Corp.**
Rating	BBB+/Negative/A-2	BBB+/Negative/A-2	BBB+/Negative/--	BBB/Negative/--
(Mil. $)				
Sales	7,221.8	4,756.7	6,686.7	9,308.0
Net income from cont. oper.	299.1	237.6	116.6	81.0
Funds from oper. (FFO)	789.6	575.1	374.4	1,766.9
Capital expenditures	517.4	299.3	689.3	995.0
Total debt	4,662.3	4,063.4	4,607.3	12,851.0
Preferred stock	54.9	46.7	116.2	38.0
Common equity	3,366.3	2,631.3	2,296.7	639.0
Total capital	8,083.5	6,741.4	7,020.2	13,528.0
Ratios				
Adj. EBIT interest coverage (x)	2.6	2.7	2.0	2.6
Adj. FFO interest coverage (x)	3.9	2.8	3.0	3.5
Adj. FFO/avg. total debt (%)	15.8	13.3	12.6	12.7
Net cash flow/capital expenditures (%)	118.1	146.6	42.4	160.3
Adj. total debt/capital (%)	59.1	61.5	58.1	95.2
Return on common equity (%)	9.1	9.1	4.7	1.3
Common dividend payout (%)	59.4	57.4	68.8	254.2

Note: Pepco Holdings' debt figures are adjusted for securitized debt at Atlantic City Electric Co. and economically defeased debt related to sale-leaseback transactions at Potomac Capital Investment Corp.

Table 3

Pepco Holdings Inc. -- Financial Summary

	--Fiscal year ended Dec. 31--		
Rating history	BBB+/Negative/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2
	2004	**2003**	**2002**
(Mil. $)			
Sales	7,221.8	7,271.3	4,323.8
Net income from cont. oper.	299.1	98.6	242.2
Funds from oper. (FFO)	789.6	804.2	660.4
Capital expenditures	517.4	598.2	503.8
Adj. Total debt	4,662.3	5,035.5	5,361.5
Preferred stock	54.9	63.2	110.7
Common equity	3,366.3	3,033.3	2,995.8
Total capital	8,083.5	8,102.0	8,468.0
Ratios			
Adj. EBIT interest coverage (x)	2.6	1.8	2.7
Adj. FFO interest coverage (x)	3.9	3.5	4.0
Adj. FFO/avg. total debt (%)	15.8	15	12.0
Net cash flow/capital expenditures (%)	118.1	105.1	104.0
Adj. total debt/capital (%)	59.1	63.3	64.2
Return on common equity (%)	9.1	3.1	6.8

Common dividend payout (%)	59.4	181.6	63.8

Note: All debt figures are adjusted for securitized debt at Atlantic City Electric Co. and economically defeased debt related to sale-leaseback transactions at Potomac Capital Investment Corp.

FORM O- QUESTION 12
ATTACHMENT I

Provide rating reports from the respective agencies for prior 36 months.

- **S&P Rating Agency Reports for 2006**

STANDARD & POOR'S RATINGSDIRECT

RESEARCH

PEPCO Holdings Inc.

Publication date: 10-Aug-2006
Primary Credit Analyst: Gerrit Jepsen, CFA, New York (1) 212-438-2529; gerrit_jepsen@standardandpoors.com

Corporate Credit Rating

BBB/Stable/A-2

Business risk profile

1 2 3 4 $\boxed{5}$ 6 7 8 9 10

Financial risk profile:
Intermediate

Debt maturities:
2006 $467 mil.
2007 $855 mil.
2008 $324 mil.
2009 $82 mil.
2010 $532 mil.

Total rated debt:
As of June 30, 2006, PHI had $5.8 billion in debt, including $480 million of securitized transition bonds at Atlantic City Electric Co. and $114 million of capital lease obligations.

Outstanding Rating(s)	
PEPCO Holdings Inc.	
Sr unsecd debt	
Local currency	BBB-
CP	
Local currency	A-2
Atlantic City Electric Co.	
Corporate Credit Rating	BBB/Stable/A-2
Sr unsecd debt	
Local currency	BBB-
Sr secd debt	
Local currency	BBB+
CP	
Local currency	A-2
Pfd stk	
Local currency	BB+
Delmarva Power & Light Co.	
Corporate Credit Rating	BBB/Stable/A-2
Sr unsecd debt	
Local currency	BBB-
Sr secd debt	
Local currency	BBB+
CP	
Local currency	A-2
Pfd stk	
Local currency	BB+
Potomac Capital Investment Corp.	
Corporate Credit Rating	BBB-/Stable/NR

Sr unsecd debt	
Local currency	BBB-
Potomac Electric Power Co.	
Corporate Credit Rating	BBB/Stable/A-2
Sr unsecd debt	
Local currency	BBB-
Sr secd debt	
Local currency	BBB+
CP	
Local currency	A-2
Pfd stk	
Local currency	NR

Corporate Credit Rating History	
May 14, 2002	BBB+
July 26, 2002	BBB+/A-2
Aug. 7, 2006	BBB/A-2

Major Rating Factors

Strengths:

- Seventy percent of consolidated cash flow is from low-operating-risk regulated transmission and distribution utilities;
- Service territories have per-capita incomes that exceed regional and national averages; and
- Exposure to cyclical industries is minimal.

Weaknesses:

- Cash flow financial measures are weak;
- Rate caps in certain jurisdictions may continue to pressure operating margins and cash flow through 2007;
- Retail and wholesale marketing operations give greater business risk; and
- Regulatory risk is heightened in multiple states.

Rationale

The ratings on diversified energy company Pepco Holdings Inc. (PHI) and its subsidiaries reflect the consolidated credit profile of its regulated and unregulated businesses, including Atlantic City Electric Co. (ACE), Delmarva Power & Light Co. (DPL), and Potomac Electric Power Co. (Pepco) as well as Conectiv Energy Holding Co. (CEH; merchant generation), Pepco Energy Services Inc. (PES; energy marketing), and Potomac Capital Investment Corp. (PCI; a portfolio of energy-related leveraged leases).

Washington, D.C.-based PHI and its subsidiaries had $5.8 billion in debt outstanding as of June 30, 2006, including $480 million of securitized transition bonds at ACE and $114 million of capital lease obligations.

PHI's business risk profile is rated a '5' (satisfactory). (Utility business risk profiles are categorized from '1' (excellent) to '10' (vulnerable).) The utilities contribute about 70% of PHI's cash flow and are expected to continue contributing about the same level for the foreseeable future. The utilities' strengths include growing energy use by residential and commercial customers, economically healthy service territories, and the absence of significant generation-related operating risk. These strengths are offset by an increasingly challenging regulatory environment in some of its jurisdictions partly due to rising commodity costs. Standard & Poor's Ratings Services considers PHI's unregulated businesses substantially more risky than the utilities due to their exposure to volatile commodity prices and very competitive retail energy markets. These risks are partially mitigated by the company's strategy to hedge a majority of its capacity over a two- to –three-year period and to refrain from participating in any speculative positions. The company's plan to expand the retail business outside its existing market also adds a measure of risk. PHI has reduced the risk profile of its unregulated financial services operations by selling many of PCI's nonenergy investments over the past few years, but the business remains exposed to IRS challenges regarding the tax deductibility of cross-border leasing transactions. Regarding the Mirant Corp. dispute about the Panda-Brandywine power contract, we assume that litigation and event risk regarding this contract are largely resolved with the favorable settlement between PHI and Mirant.

The ratings reflect a consolidated financial profile commensurate with a 'BBB' rating. Adjusted funds from operations (FFO) to total debt (adjusted for operating leases, securitized debt, and retirement obligations) was weak for the rating, at about 10% as of year-end 2005 and about the same for the 12 months ended March 31, 2006. This ratio declined from about 14% at year-end 2004 partly due to a one-time reduction in deferred taxes in 2005 to reflect the company's then-expected tax payment in early 2006 related to the mixed service cost issue. This significantly reduced FFO in 2005. Adjusted FFO interest coverage also dipped to slightly less than 3x because of the same reduction, whereas historically this measure has averaged slightly over 3x, which is well within the 'BBB' benchmark range. Adjusted debt to total capital is over 60%, which is high for the rating and which exceeds the bottom of the 'BBB' benchmark range for this ratio. Although these ratios may strengthen with an improvement in cash flow after the expiration of rate freezes in Maryland (2006) and the District of Columbia (2007), this improvement depends on supportive regulation through rate relief, which in Standard & Poor's view could be at risk given the heightened regulatory uncertainty in multiple jurisdictions. The rating also incorporates our expectation that the company will recover the construction costs that it will incur as part of its capital spending program, particularly if it implements its proposed $1.25 billion transmission project.

Short-term credit factors

PHI's short term rating is 'A-2' and reflects Standard & Poor's expectation that PHI will retain significant available capacity under its credit facilities to meet its liquidity requirements and any cash payments resulting from collateral calls. Standard & Poor's expects that PHI utilities will continue generating stable cash flow and that discretionary cash flow will be slightly negative to modestly positive over the next few years. As of June 30, 2006, remaining debt maturities in 2006 were $252 million. Given the stable nature of the majority of cash flows, PHI's and its subsidiaries' liquidity is adequate.

As of June 30, 2006, PHI had $33 million of cash and cash equivalents. In addition, PHI has a $1.2 billion credit facility agreement that matures in 2011 and that is available to PHI and its utilities with sublimits. PHI can draw $700 million, and its utilities can draw up to $300 million each with a $500 million aggregate limit. The credit facility primarily backs up the $1.2 billion CP program that as of June 30, 2006, had $620 million outstanding.

Outlook

The stable outlook on PHI and its subsidiaries reflects Standard & Poor's expectation of steady performance through 2007. The outlook could revised to positive if the company successfully executes its regulatory filings and receives supportive and timely rate recovery of power and other transmission and distribution (T&D) costs, and if financial measures subsequently improve. The outlook could be revised to negative if supportive rate relief is not provided over the next few years and if there is materially adverse outcome from any IRS challenges of the company's leveraged lease investments.

Business Description: Company Family Includes Regulated And Unregulated Units

PHI is a diversified energy company with regulated T&D utilities (70% of consolidated operating income) serving the District of Columbia (Pepco); Montgomery and Prince George's counties in Maryland (Pepco); sections of northeastern Maryland (DPL); southern New Jersey, including Camden (ACE); Delaware (DPL); and small sections of Virginia (DPL). PHI's regulated sales derive from operations in Maryland (38%), the District of Columbia (22%), Delaware (20%), New Jersey (19%), and Virginia (1%).

Unregulated businesses include CEH (15% of consolidated operating income), the owner and operator of 3,698 MW of mostly midmerit electricity generating capacity in the Pennsylvania-New Jersey-Maryland (PJM) East Interconnection that manages and optimizes its generation portfolio during peak demand periods. Other unregulated businesses include PES (5% of consolidated operating income), one of the largest sellers of retail electricity and natural gas services in the mid-Atlantic region, and a provider of energy management services in the Mid-Atlantic region. A portfolio of energy-leveraged leases in Europe and Australia is held through PCI (10% of consolidated operating income).

Rating Methodology: Consolidated Business And Financial Profiles Serve As Basis

The ratings on PHI and its subsidiaries are based on PHI's consolidated business and financial risk profile, which includes regulated and unregulated operating units. PHI's senior unsecured debt obligations are rated one notch lower than the corporate credit rating due to the structural subordination of holding company debt to the priority debt issued at PHI's utilities. PHI's unsecured debt rating is rated one notch lower than the corporate credit rating because of the structural subordination of these obligations to the debt of the operating utilities. First mortgage bonds are rated one notch higher than the corporate credit rating to incorporate Standard & Poor's analysis of the collateral backing the first mortgage bond indenture. The company's preferred stock is rated two notches below the corporate credit rating, based on the subordinated characteristics of preferred stock.

Business Risk Profile: Diversified Operations Mean More Risk

PHI's business risk profile is satisfactory. The company's operations in the volatile wholesale and retail energy marketing businesses result in PHI's business risk profile being more risky than that of companies that are only T&D operations. Peers with similar business lines and similar risk profiles include Northeast Utilities and Energy East Corp.

Regulation

PHI's T&D utilities operate in four states and are regulated by multiple public service commissions (PSC) and by the FERC for transmission rates. Operating in multiple states provides moderate regulatory diversification and mitigation of any adverse regulatory outcome or lag in rate recovery. This reduces the risk that any one jurisdiction could unduly impair consolidated financial performance, but it requires solid management of the various regulatory risks and the ability to influence policies in multiple jurisdictions.

Most of the states that PHI serves have transitioned to a fully deregulated wholesale electricity market. In 1999, the Maryland, District of Columbia, Delaware, and New Jersey commissions established a multiyear transition period during which PHI utilities were required to cap distribution rates in return for recovery of approved stranded costs. During the transition period, base rates include a tariff for purchased-power costs based on prevailing average fuel prices and generation costs in 1999, as well as a fixed distribution tariff that provides a fixed return to the utility. New Jersey completed its transition in 2003, followed by Maryland in 2004, the District of Columbia in 2005, and Delaware in 2006. Although the transmission and distribution rate caps were originally scheduled to terminate with the conclusion of the transition periods in Maryland, the District of Columbia, and Delaware, the commissions extended the rate caps two years as a condition for approving the Conectiv merger. Remaining distribution rate caps extend to year-end 2006 in Maryland, September 2007 in the District of Columbia, and year-end 2010 in Virginia. As a result of wholesale electricity deregulation, all of PHI's utilities elected to sell the majority of their power generating assets and focus on the lower-risk T&D segment of the electricity business, and retain the standard offer service (SOS) obligation to procure power supplies on behalf of customers that do not choose a retail power supplier.

The Maryland, District of Columbia, and Delaware commissions provide for Pepco and DPL to earn a nominal margin on the energy delivered to SOS customers. Although we do not expect these margins to be key cash flow drivers, the additional margins earned on SOS customers help temper remaining distribution rate freezes, distribution rate reductions, and power cost deferrals. Standard & Poor's monitors regulatory actions such as the power cost deferrals because 70% of PHI's consolidated operating income is from energy delivery operations that depend largely on the actions of regulatory agencies for earnings and cash flow. Adverse rulings that result in a deferral or disallowance of incurred costs could reduce consolidated cash flow and could have a long-lasting effect on credit quality and ratings.

Delaware. Retail choice for DPL customers in Delaware was implemented in 2000 after the enactment of a restructuring law. SOS rates were ultimately frozen to May 1, 2006, after an initial freeze was extended in 2002 as part of the PHI and Conectiv merger. In October 2005, DPL agreed to continue to provide SOS to all customer classes, with the power to meet SOS customer requirements to be procured through an annually conducted customer-class-specific request for proposals (RFP) process, and SOS prices to reflect those contained in the winning contracts. There is currently only minimal customer switching by non-residential customers. In December 2005, DPL issued RFPs for 1,700 MW of full-requirements power. Based on the results of the RFP, SOS prices were scheduled to increase: 59% for residential/small commercial and industrial customers; 67% for mid-general service; and more than 100% for other general service. DPL proposed to phase in increasing power prices for residential and small commercial SOS customers effective May 1, 2006, following the end of the rate freeze. DPL filed its proposal after Delaware's governor ordered the Delaware PSC to report about actions that can be taken to minimize the expected power supply rate increases to DPL customers beginning May 1, 2006. Ultimately, power rates for residential/small C&I customers are being phased in with a 15% increase as of May 1, 2006, 25% incremental increase as of January 1, 2007, and the remainder on June 1, 2007. Since the deferral proposal was implemented, the company is accruing the under-recovered portion of these higher power costs through mid-2007 when the deferral is expected to rise to roughly $55 million (after tax) with subsequent rate recovery of this accrued balance through mid-2009.

In addition to the power cost deferral proceeding in the spring of 2006, DPL requested a nominal electric base rate increase and the transfer of $3.5 million from distribution to supply rates. This filing was required as a provision of a PSC-adopted settlement in PHI/Conectiv merger. The Delaware PSC order an $11 million distribution rate reduction based on a 10% return on equity (DPL requested an 11% ROE) and authorized a $5 million transfer of distribution costs to supply rates. The net reduction was about $6 million.

District of Columbia. Legislation enacted in 2001 in the District of Columbia mandated the phase-in of customer choice for electric generation and required Pepco to provide SOS to customers who declined to select a competitive supplier, with generation rates frozen through Feb. 8, 2005. In 2004, the District of Columbia PSC required Pepco to continue to supply SOS to customers through May 2011 for residential and small commercial customers, and through May 2007 for large commercial customers. The power to meet SOS requirements is to be procured through annual competitive wholesale bids. For residential customers, Pepco is required to solicit fixed price offers for full requirements service for terms of one, two, and over two years, such that 40% of residential SOS load is supplied by contracts with terms of three or more years. For nonresidential customers, Pepco must solicit fixed-price offers for full-requirements service for one- and two-year terms, such that two-year contracts make up at least 40% of the portfolio. Nonresidential customers on fixed-price service are required to remain on such service for a minimum of 12 months. If they decline to commit to the 12-month stay requirement, they are served under market-priced service, which is an hourly priced SOS. The prices of such offerings are based on the locational marginal price set by the PJM Regional Transmission Organization. Although distribution rates are capped through August 2007, Pepco expects to file a rate case in the fall of 2006.

Maryland. In 2000, full retail access was implemented in Maryland along with rate freezes. Utilities remained the provider of –last resort (POLR) through their respective transition periods, with SOS provided under capped rates. As of July 2004, residential rates were no longer capped. Pepco and DPL are to provide SOS in Maryland through May 2008. Following a recent Maryland auction, the power prices for DPL's SOS customers were expected to increase 35% for residential, 40% for small commercial, and 14% for medium commercial, all effective June 1, 2006. Pepco's auction resulted in SOS price increases of 39% for residential, 55% for small commercial, and 52% for medium commercial, all effective in June 2006. To minimize the effect of significantly higher power costs on Maryland residential ratepayers, DPL and Pepco filed a settlement in a Maryland PSC-initiated investigation that proposed a phase-in of the higher power costs for their residential SOS customers. The power cost increases will be phased in 15% as of June 1, 2006, 15.7% on March 1, 2007, and the remainder June 1, 2007, with recovery of the deferral balance through year-end 2008. About 1% of eligible customers chose to opt in to the program (versus opt out in Delaware), resulting in a $1 million deferral balance. In Maryland, DPL and Pepco are expected to request electric base rate increases before year-end 2006. Any ruling that would disallow capital improvements or rate recovery of higher operating and maintenance expenses, or that would result in a significantly lower authorized return, would be considered negative for credit quality and could affect ratings.

New Jersey. Beginning in 2003, New Jersey T&D utilities have procured power through auctions. This change in the power acquisition process occurred simultaneously with the termination of T&D rate caps that began in 1999, and enabled ACE to eliminate exposure to market price fluctuations and obviated the need to seek future recovery of deferred balances. In a past decision, the New Jersey Board of Public

Utilities (NJBPU) disallowed $45 million in deferred balances that ACE incurred between 1999 and August 2003. The company continues to litigate this disallowance. In addition to approving recovery of only 75% of ACE's estimated $195 million in deferred balances, the NJBPU authorized recovery over 10 years versus four years as contemplated in 1999.

ACE's distribution rates are not capped. In 2003, the utility sought NJBPU authority to increase base rates to recover costs incurred during the market transition period. Under a settlement reached in 2005, base rates were not increased, but the utility was able to begin recovering $117 million in deferred restructuring charges over the four years.

Virginia. In Virginia, DPL serves 20,000 customers in the Delmarva Peninsula. DPL proposed a 43% rate increase for residential customers taking default service to reflect the higher energy cost established through a competitive bid process. The Virginia State Corporation Commission has directed DPL to address whether the proxy rate calculation as established in 2000 should be applied. If applied, DPL could incur a small loss. Except under certain instances, distribution rates will be capped through 2010.

FERC. In addition to distribution rate proceedings, the company has made filings with the FERC seeking transmission rate increases. In April 2006, the FERC approved a settlement that provides for a 10.8% ROE for existing facilities and an 11.3% ROE for facilities placed in service after Jan. 1, 2006. The new rates were effective June 1, 2006, and included a true-up of rates set as of June 1, 2005, and projects expected to be online in 2006. The transmission rate base was $880 million as of year-end 2005. Recently completed projects include a 230 kilovolt (kV) transmission line in ACE's service territory that was finished in 2005 for $112 million. Other transmission projects are expected in ACE's, DPL's, and Pepco's service territories over the next several years for a projected $275 million.

In addition to the smaller projects, PHI has proposed a $1.24 billion transmission project, the PHI Mid-Atlantic Power Pathway, that is projected to be constructed in segments, beginning in 2007 and ending in 2014. The project would mostly be built on or next to existing right-of-ways and would be largely along established transmission corridors through rural areas. The largest component is a 230-mile, 500 kV line stretching from northern Virginia through Maryland (underneath Chesapeake Bay) to Delaware, where it would continue up to southern New Jersey. A lesser component will consist of 230 kV lines that would support Maryland, Delaware, and New Jersey. The project costs are expected to be allocated to the DPL service territory (77%), Pepco (15%), and ACE (8%). The project would be expected to improve reliability in Washington, D.C., the Delmarva Peninsula, and southern New Jersey. Congestion should be reduced and utilities should have access to lower-cost power.

Markets

PHI serves strong markets that is comprised of sales to residential (35%), commercial (46%), industrial (9%), and government (10%) customers. Although overall sales growth is about 2%, PHI benefits from service areas that are more affluent and economically stable than other U.S. regions. Pepco enjoys a service territory that has household income levels that are 15% higher than national averages and has almost no exposure to the often-volatile energy demand of heavy industrial customers. Unemployment in the District of Columbia region is also below national averages due to the presence of the federal government as the region's largest employer. Overall, Standard & Poor's believes that PHI's utilities have an appropriately diversified customer base that is capable of absorbing any rate increases that may result from escalating power costs in their respective service areas.

Operations

Regulated utilities. Operational risk associated with T&D activities is low and supports PHI's current ratings. Reliability statistics at Pepco, DPL, and ACE are generally consistent with the outage rates of similar utilities. ACE and DPL are addressing major reliability initiatives through transmission construction programs aimed at reducing congestion on the Delmarva Peninsula and at increasing transmission capacity into southern New Jersey after the BL England generating plant closes in 2007.

In general, operational risk at Pepco has decreased as a result of the wholesale electricity auctions that are currently in place in New Jersey, Delaware, Maryland, and the District of Columbia. Each of the utilities benefits from a more diversified base of power suppliers and is better protected from a supplier default by regulatory provisions that allow other market participants to quickly assume any unsatisfied load obligations that arise from a bankruptcy.

Event risk surrounding litigation with Mirant Corp. was eliminated following a settlement with the generator, slightly reducing PHI's business risk. In 2000, Mirant assumed two PPAs from Pepco as part of an asset purchase and sale agreement (APSA) that was executed in the same year. Under the APSA, Pepco sold most of its power generating assets to Mirant for $2.65 billion and Mirant agreed to reimburse Pepco for expenses from out-of-market PPAs with FirstEnergy Corp. (expired year-end 2005) and independent power producer Panda-Brandywine L.P. (expires year-end 2021). Because FirstEnergy and Panda did not authorize Pepco to assign the PPAs to Mirant, Pepco entered into a "back-to-back agreement" with Mirant that mirrored the utility's obligations under the power contracts. In practice, Mirant does not request power directly under the back-to-back agreement. Instead, Mirant reimburses Pepco the difference between what it pays for the PPA power costs and any amount it receives through reselling the power. The event risk surrounding the litigation with Mirant was eliminated, mitigating the modest effect that it had on PHI's consolidated business risk profile. PHI's cash flow should remain largely unchanged because payments that were made by Mirant will be made from a special-purpose account that will be created to hold the settlement proceeds. If payments from the special-purpose account are insufficient, the utility may request rate recovery of these costs. However, Standard & Poor's expects that any rate recovery from state regulators, if authorized, would lag Pepco's initial cash outflows, resulting in less support for PHI's consolidated rating, at least in the short term.

ACE continues to divest generation assets. In third-quarter 2006, it is expected complete the sale of its minority ownership (108 MW) interest in the Keystone and Conemaugh coal-fired generation plants in western Pennsylvania to Duquesne Light Holdings for about $175 million. ACE's BL England 447 MW coal- and oil-fired facility remains on the market, and the utility received final bids in an April 2006 auction. The ultimate acquirer would assume all the plant's environmental liabilities. If ACE does not sell the plant, it will close the facility due to the level of environmental compliance costs, and as part of a settlement adopted by the NJBPU related to the closure, ACE has been authorized to issue securitization bonds to recover stranded costs that are in part related to the plant. The settlement also allowed ACE to waive its adherence to mandated emissions standards in return for the plant's closure, which is expected to occur by 2008. As part of the settlement, ACE agreed to build interstate transmission lines and upgrade existing power lines to enhance the ability to import power into southern New Jersey.

Conectiv Energy Holding Co. PHI's unregulated activities increase the business risk of the consolidated entity. PHI's primary unregulated business is CEH, which owns a portfolio of merchant power generating assets in the PJM Interconnection. The 3,698 MW generation fleet is 9% baseload coal capacity, 73% intermediate-dispatch gas-fired facilities, and 18% peaking resources. CEH's strategy is to capitalize on the operational flexibility of its generating assets to sell power into transmission-constrained portions of the PJM East market during periods of rising prices. In 2004, CEH was able to earn positive margins despite weak market conditions due to the completion of the Conectiv Bethlehem power facility (a 1,082 MW combined-cycle gas turbine in PJM East) in 2003 for $335 million. The Bethlehem facility can respond more quickly to changing market conditions than can typical gas- and oil-fired combined-cycle facilities in the region, due to shorter minimum run time and ramp-up requirements, and its ability to dispatch more often than its competitors. This allows CEH to be more selective in its sales commitments and to restrict its operations to those periods that are most profitable. Although the completion of the Bethlehem project improved CEH's profitability and competitive position in 2004, wholesale operations continue to introduce cash flow volatility into PHI's consolidated financial profile. Standard & Poor's estimates that CEH will contribute roughly 15% of PHI's consolidated cash flow over the next few years.

Pepco Energy Services Inc. Other unregulated businesses include retail energy provider PES. Standard & Poor's considers retail energy marketing risky, like CEH's wholesale activities. However, both of these businesses increase the consolidated liquidity requirements of PHI and generate modest margins relative to their risk. Standard & Poor's expects PES' risk profile to increase as PHI expands its retail energy operations outside its service territories. Any growth in the number of longer-dated, fixed-price retail contracts at PES will require additional liquidity to support energy payables and collateral obligations. PHI has sufficient unused capacity in its credit facility to adequately support these obligations at both CEH and PES.

Potomac Capital Investment Corp. PHI's business risk profile reflects PCI's portfolio of cross-border energy leases that reflect the sale by, and lease back to, the seller (lessee) of an energy-related asset. The energy-related asset was financed through a combination of nonrecourse third-party debt issued by overseas commercial banks and a lease equity contribution. PHI's lease equity was funded through capital market debt issued by Pepco Holdings or PCI. The seller/lessee placed sale proceeds from the transaction in an account for the benefit of PHI and the nonrecourse lenders if a lease defaults. Collateral held in trust includes U.S. Treasury notes, USAID bonds, payment undertaking arrangements, LOCs posted by financial institutions that are rated at least 'AA', and surety bonds. Other sources of collateral include the parent guarantees of investment-grade sellers/lessees and the underlying value of the physical facilities.

PHI currently derives $55 million annually in tax benefits, and thereby cash flow, from deductions for interest on the nonrecourse debt and depreciation of the energy assets. Over the period from 2001 to March 31, 2006, PHI claimed about $245 million in tax benefits. In February 2005, the Treasury Department and the IRS indicated in a general notice to taxpayers that the tax benefits realized from such sale-leaseback transactions would be challenged. In addition, the IRS issued PHI a notice in May 2005 challenging the tax benefits the company realized from the interest and depreciation deductions that PHI claimed for the 2001 and 2002 tax years. If the IRS prevails, PHI would pay additional taxes with interest and penalties, reducing the company's cash flow. An adverse decision by the IRS could negate the benefit of PCI to its parent, and could expose PHI to unexpected cash payments. A disallowance of tax benefits from these leases would require PHI to reduce the leases' book value, currently $1.3 billion, and record a charge to earnings. The uncertainty surrounding the continuation of the tax benefits through the terms of the leases weakens PHI's business risk profile and could affect the company's financial risk profile.

Competitiveness

PHI's regulated utilities have an above-average competitive position as the sole T&D providers in their service territories. In 2004, Pepco's residential rates in Maryland and the District of Columbia were $83.10 per megawatt-hour (MWh) as compared with the $98.12 per MWh average for the MAAC region. Residential rates at ACE averaged $119.03 per MWh and are among the highest in the MAAC region. Commercial and industrial rates at ACE average $110.78 per MWh and 97.44 per MWh, respectively, exceeding the average of utilities rated by Standard & Poor's. DPL's rates have been lower than average for the region and S&P's rated utilities, but the recent power rate increase may bring the utility's average rates closer to the regional average.

Customer shopping for retail electricity is significant throughout PHI's service areas. In 2004, customer choice programs represented about 32% of total load in the District of Columbia, 28% in Maryland, and 22% in New Jersey. Although higher customer shopping results in lower SOS margins, PHI generates the majority of its utility revenues through charges for using its wires, which has little competition.

Table 1 details the rates of PHI's regulated utilities.

Table 1

Pepco Holdings Inc. Regulated Utilities Rate Analysis

($/MWh)

Company	Residential rate	Commercial rate	Industrial rate
Atlantic City Electric Co.	119.03	110.78	97.44
Delmarva Power & Light Co.	85.79	75.03	56.19
Potomac Electric Power Co.	83.10	74.09	51.35
Mid-Atlantic Area Council average	98.12	90.62	71.05
Standard & Poor's Ratings Services average	98.65	88.74	66.03

Source: Platt's Powerdat database. MWh--Megawatt-hour.

Management

PHI has apparently been managed more conservatively in recent years due to the cessation of proprietary trading at CEH, the sale of non-energy assets from PCI's investment portfolio, and the sale of the telecommunications joint venture (Starpower) in December 2004. Standard & Poor's expects PHI to retain its current mix of businesses over the next several years, and business risk could further decline if management continues its risk reduction efforts. Management continues to demonstrate its commitment to credit quality, as evidenced by the ongoing execution of its debt-reduction plan and the $275 million equity issuance in 2004 that was used to support debt reduction objectives.

Financial Risk Profile: Unfavorable Cash Flow Measures Are A Key

Factor

Standard & Poor's considers PHI's financial risk profile to be intermediate to slightly aggressive because of weak cash flow measures, multiple off-balance-sheet (OBS) adjustments, less stable cash flows from riskier nonregulated businesses, and a capital structure with over 60% debt leverage.

Accounting

In conducting its credit analysis of PHI, Standard & Poor's has made multiple adjustments to reported financial figures. When calculating credit measures, Standard & Poor's considers OBS obligations such as operating leases and purchase-power agreements to be fixed commitments, and imputes debt and interest components, including these amounts in adjusted financial ratios. After accounting for operating leases, PHI's debt and interest expense increase by about $360 million and $22 million, respectively. FFO is increased by $16 million of imputed depreciation on operating leases. Standard & Poor's does not attribute a debt equivalent to purchased-power obligations resulting from the Basic Generation Service auctions in New Jersey or the SOS auctions in Maryland, the District of Columbia, and Delaware.

We also adjust reported financial results for pension and postretirement obligations (on a tax-adjusted basis). For PHI, this increases adjusted debt by $393 million for the unfunded projected benefit obligations, reduces equity by $335 million, and increases FFO by $41 million. PHI's aggregate pension funding ratio, at about 90% (Standard & Poor's defines this ratio as the fair value of the plan assets relative to the plan's projected benefit obligation), is above average for diversified energy companies and slightly below average for T&D utilities.

In addition to adjustments for operating leases and postretirement obligations, Standard & Poor's adjusts PHI's financial ratios to reflect securitized debt issued by ACE. Because debt service for the securitized stranded costs at ACE are collected through a non-bypassable charge paid by all utility customers, interest and amortization on the securitized debt is subtracted from gross revenues, reported interest expense, and reported amortization amounts.

PHI's utilities benefit from the implementation of regulatory accounting, SFAS 71 (accounting for the effects of certain types of regulation), which requires deferral of, for future recovery or refund, certain costs and obligations that would otherwise be immediately recognized as revenue and expenses. As of year-end 2005, the company's regulatory assets were about $1.2 billion and regulatory liabilities were about $594 million. About 70% of these regulatory assets represent stranded costs that PHI has already recovered through the issuance of transition bonds by Atlantic City Electric Transition Funding LLC. The remainder of PHI's net regulatory asset balance is a combination of deferred recoverable income taxes, deferred debt extinguishment costs, deferred other postretirement benefit costs, and unrecovered purchased-power contract costs. Standard & Poor's has not adjusted the financial statements related to these assets and liabilities, due to their regulatory creation and recovery through rates.

In August 2005, the IRS issued rulings on mixed service costs that gave guidance on whether certain service costs can be expensed or if they should be capitalized and depreciated. In 2001, ACE, DPL, and Pepco changed how they accounted for construction costs that allowed the utilities to accelerate the deduction of certain expenses for tax purposes that were previously capitalized and depreciated. This produced a lower tax obligation and improved cash flow. If the IRS ruling is upheld, it would limit PHI's ability to use this method of accounting for tax purposes on the tax returns before the 2005 tax year. PHI would be required to capitalize and depreciate a portion of the previously expensed construction costs and repay the associated income tax benefits along with interest. In its 2005 10-K, PHI indicated that these accelerated deductions generated incremental tax cash flow benefits of about $205 million, mainly for the 2001 tax returns of its utility subsidiaries.

On the same day as the IRS ruling, the Treasury Department released regulations to taxpayers on mixed service costs that would require PHI's utility subsidiaries to change their accounting regarding construction costs for income tax purposes, beginning with the 2005 tax year. Under the new method, the utilities will have to capitalize and depreciate some construction costs and reflect the effect of this adjustment in taxable income over two years, starting with the 2005 tax year. In early 2006, PHI paid taxes of $121 million to cover the amount that is estimated to be payable after a final method of tax accounting is adopted for the 2005 tax year. It is uncertain if additional taxes will be made for this tax accounting adjustment related to 2005 and earlier years. In 2005, FFO and related financial measures were reduced because of a deferred tax decrease associated with this adjustment for the 2005 tax year. A revision of the deferred tax level should result in larger utility rate bases and, if future rate relief reflects the higher levels, may strengthen cash flow.

Corporate governance/Risk tolerance/Financial policies

In recent years, management has become more risk averse following the termination of CEH's proprietary trading, the sale of non-energy assets from PCI's investment portfolio, and the sale of a telecommunications joint venture (Starpower). Standard & Poor's expects PHI to retain its current mix of businesses over the next several years, and expects business risks to possibly decline due to management's ongoing risk-reduction efforts. This current operational risk reduction is partly offset by historically aggressive use of debt, which continues to weigh on PHI's capital structure and reduced creditworthiness. For example, PHI acquired Conectiv for $2.2 billion, including $1.4 billion of goodwill, and financed the acquisition with a $1.1 billion cash offer and $1.1 billion of common stock. The cash portion was funded with $700 million of new debt and $400 million in proceeds from Pepco's sale of its generating assets to Mirant Corp. PHI also financed $640 million in new long-term debt to retire bank loans and CP that were due after the acquisition. PHI has subsequently been reducing debt with internally generated cash flow and equity issuances.

Cash flow adequacy

Regulated operations generate about 70% of PHI's cash flow. As of year-end 2005, the unadjusted FFO interest coverage ratio was 2.5x, whereas on an adjusted basis it was 2.6x. Unadjusted FFO to total debt was 9.5%, and the adjusted level was slightly better at about 10%. Due to a one-time reduction in deferred taxes in 2005 to reflect the company's then-expected tax payment in early 2006 related to the mixed service cost issue, FFO dipped significantly, resulting in weaker cash flow measures. After adjustments, Standard & Poor's expects these cash flow measures to improve over the next several years as cash flow strengthens and as debt and interest expense are reduced. Standard & Poor's expects capital spending to average about $500 million annually over the next three years, largely because of new customer connections, reliability initiatives, and load-related PJM initiatives.

Free operating cash flow, which is FFO after capital expenditures, should remain positive through 2007, and discretionary cash flow should be slightly negative to nominally positive after factoring in dividends, which are not expected to significantly increase. Net cash flow, which is FFO less dividends, relative to capital expenditures is expected to improve to over 100% by 2007, an improvement over historical levels that have hovered in the range of 85-95%. All these cash flow ratios are expected to improve as financial performance strengthens and FFO increases, with rate freezes concluding in most regulatory jurisdictions and deferred power costs being recovered through rates. PHI paid dividends in 2005 and 2004 at about 55% and 70% of earnings, respectively, and increased its 2005 dividend to $1.04 from $1, or a 4% increase effective in 2006.

Capital structure/Asset protection

On an adjusted basis, PHI is more highly leveraged than the 'BBB' benchmark range of 50% to 60% for a '5' business risk profile. Adjusted debt to total capital continues to hover around 64%. Unadjusted debt to total capital was 62.4% in 2004, a reduction from 65.5% in 2004. In a few years, the adjusted figure may be under 60%, which would be within the benchmark range. The consolidated company's financial profile continues to be weakened by higher leverage that resulted in part from the Conectiv merger. Management continues to target debt reduction as part of its financial strategy. The capital structure was strengthened when debt and preferred stock were reduced in 2004 by $480 million, which was partly funded with the common equity issuance. Approximately 90% of PHI's outstanding debt is long-term debt, and the remainder consists of variable rate demand notes, the current portion of long-term debt, and CP. About 30% of outstanding debt is secured in the form of first mortgaged bonds or senior secured notes. PHI's exposure to interest rate risk is minimal since about 10% of total debt outstanding is variable rate. In addition to periodic common stock offerings, PHI has been issuing common equity of $30 million annually through its dividend reinvestment program.

Table 2

PEPCO Holdings Inc. Peer Comparison

	--Average of past three fiscal years--				
	PEPCO Holdings Inc.	Energy East Corp.	Northeast Utilities	PPL Corp.	Consolidated Edison Inc.

Rating as of Aug. 4, 2006	BBB+/Watch Neg/A-2	BBB+/Stable/A-2	BBB/Stable/NR	BBB/Stable/NR	A/Negative/A-2
(Mil. $)					
Total revenues	7,437.3	4,883.0	6,454.7	5,744.2	10,425.0
Net income from cont. oper.	241.4	233.9	2.8	698.3	602.0
Funds from operations (FFO)	692.4	660.1	600.4	1,548.2	1,493.8
Capital expenditures	597.0	317.0	685.3	786.5	1,548.2
Cash and investments	88.2	224.4	45.4	549.0	52.0
Total debt	5,737.6	4,568.4	3,425.0	8,520.8	8,669.7
Preferred stock	54.7	54.1	116.2	51.0	213.0
Common equity	3,018.4	2,435.2	1,906.6	3,673.0	5,713.5
Total capital	8,810.7	7,057.7	5,428.4	12,300.1	14,637.2
Adjusted ratios					
EBIT interest coverage (x)	2.4	2.2	2.4	2.9	2.5
FFO int. cov. (x)	3.0	3.1	4.1	4.0	3.8
FFO/total debt (%)	12.1	14.4	17.5	18.2	17.2
Discretionary cash flow/total debt (%)	0.3	0.9	(4.88)	4.9	(8.50)
Net cash flow/capital expenditure (%)	85.5	164.6	75.4	157.2	65.2
Total debt/total capital (%)	65.1	64.7	63.1	69.3	59.2
Return on common equity (%)	5.5	8.6	4.8	21.8	7.8
Common dividend payout ratio (unadj.) (%)	59.1	58.0	(148.95)	47.6	78.7

Note: Figures are fully adjusted, including postretirement obligations.

Table 3

PEPCO Holdings Inc. Financial Summary

	--Fiscal year ended Dec. 31--			
	2005	**2004**	**2003**	**2002**
Rating history	BBB+/Negative/A-2	BBB+/Negative/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2
(Mil. $)				
Total revenues	8,013.3	7,119.0	7,179.7	4,292.1
Net income continuing	362.2	260.6	101.4	210.5
Funds from operations (FFO)	568.1	761.8	747.3	713.1
Capital expenditures	462.9	700.2	627.7	672.4
Cash and investments	121.5	29.5	113.6	82.5
Total debt	5,864.0	5,564.3	5,784.5	5,951.1
Preferred stock	45.9	54.9	63.2	110.7
Common equity	3,249.4	3,063.9	2,741.9	2,749.7
Total capital	9,159.4	8,683.1	8,589.6	8,811.5
Adjusted ratios				
EBIT interest coverage (x)	2.5	2.6	2.1	3.0
FFO int. cov. (x)	2.6	3.2	3.2	4.3
FFO/total debt (%)	9.7	13.7	12.9	12.0
Discretionary cash flow/total debt (%)	6.4	(3.31)	(2.50)	0.2
Net cash flow/capital expenditure (%)	81.4	83.3	91.1	85.7
Total debt/total capital (%)	64.0	64.1	67.3	67.5
Return on average equity (%)	10.2	7.9	3.0	8.5
Common dividend payout ratio (unadj.) (%)	N.M.	52.5	68.3	176.3

Note: Figures are fully adjusted, including postretirement obligations. N.M.--Not meaningful.

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The McGraw-Hill Companies

FORM O- QUESTION 13
ATTACHMENT II

Provide a statement regarding the proposed guarantor's willingness to provide guarantee.

Response to Question on Form O-Financial Information, Delmarva Power Generation and Power Purchase Agreement RFP, attachment 2 Bidder Response Form

Question 13. Provide a statement regarding the proposed guarantor's willingness to provide guarantee acceptable to DPL.

PHI has been identified as the proposed guarantor of the security requirements required under the proposed Power Purchase agreement between Conectiv Energy and DPL. PHI would be willing to provide required amounts of guarantees assuming the final form of the guarantee and the associated Power Purchase Agreement were acceptable to both Conectiv Energy and PHI. The guarantee will be for a certain defined amount which will vary depending on the size of the project and related Power Purchase Agreement which is ultimately negotiated.

Anthony Kamerick,
Vice President and Treasurer
Pepco Holdings, Inc.

FORM O - ATTACHMENT III

Response to Question 15d

What is the current availability and usage under the liquidity / credit line, provide historical, minimum, maximum, and average for the last 24 months.

FORM O – QUESTION 15d
ATTACHMENT III

Date	Commercial Paper Outstanding	Letter of Credit Outstanding	Combined Outstanding
12/31/2004	$78,600,000	$10,475,152	$89,075,152
1/31/2005	$103,000,000	$13,285,919	$116,285,919
2/28/2005	$120,000,000	$7,614,108	$127,614,108
3/31/2005	$67,000,000	$7,626,142	$74,626,142
4/30/2005	$34,400,000	$7,067,605	$41,467,605
5/31/2005	$150,000,000	$13,025,172	$163,025,172
6/30/2005	$0	$13,030,159	$13,030,159
7/31/2005	$0	$12,601,530	$12,601,530
8/31/2005	$0	$12,603,693	$12,603,693
9/30/2005	$0	$22,946,697	$22,946,697
10/31/2005	$0	$22,928,316	$22,928,316
11/30/2005	$0	$22,943,558	$22,943,558
12/31/2005	$0	$29,608,024	$29,608,024
1/31/2006	$0	$30,384,425	$30,384,425
2/28/2006	$378,000,000	$30,422,571	$408,422,571
3/31/2006	$335,315,000	$60,922,571	$396,237,571
4/30/2006	$278,500,000	$60,828,601	$339,328,601
5/31/2006	$300,000,000	$35,828,601	$335,828,601
6/30/2006	$382,203,000	$35,846,442	$418,049,442
7/31/2006	$364,277,000	$37,616,035	$401,893,035
8/31/2006	$59,000,000	$65,139,100	$124,139,100
9/30/2006	$87,000,000	$106,625,534	$193,625,534
10/31/2006	$0	$208,875,534	$208,875,534
11/30/2006	$0	$204,609,534	$204,609,534
AVG	$114,053,958	$44,702,293	$158,756,251

FORM O - ATTACHMENT IV

Response to Question 16

CESI's Conclusion on FIN 46

FORM O – QUESTION 16
ATTACHMENT IV

<u>FIN 46(R) Evaluation of Delaware RFP</u>

This evaluation is intended to satisfy the request in the RFP from Delmarva Power and Light Company (Delmarva) in Form O, Question 16. Conectiv Energy is proposing construct a Combined Cycle Generation facility nominally rated for 180 MW in a 1 X 1 configuration. Delmarva (an affiliate of Conectiv Energy) needs assurance that it will not be required to consolidate this project into its separate financial statements as a variable interest entity under FIN 46(R).

Delmarva might be required to consolidate the Conectiv Energy project if any of the three conditions of FIN 46(R) Paragraph 5 are satisfied. These have been evaluated as follows:

- 5(a) The total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by any parties, including equity holders.
  - Conectiv Energy will provide all of the equity for the project using its own funds, or funds obtained from the parent company (PHI).
  - This incremental addition to Conectiv Energy's generation fleet will only amount to approximately 5% of the total fleet capacity.
- 5(b) As a group the holders of the equity investment at risk lack any one of the three characteristics of a controlling financial interest.
  - Decision making rights are retained by Conectiv Energy.
  - Price and operational risks are borne by Conectiv Energy.
  - Residual returns are retained by Conectiv Energy.
- 5(c) The equity investors as a group also are considered to lack decision making rights if (i) the voting rights of some investors are not proportional to their obligations to absorb the expected losses of the entity, their rights to receive the expected residual returns of the entity, or both and (ii) substantially all of the entity's activities (for example, providing financing or buying assets) either involve or are conducted on behalf of an investor that has disproportionately few voting rights. For purposes of applying this requirement, enterprises shall consider each party's obligations to absorb expected losses and rights to receive expected residual returns related to all of that party's interests in the entity and not only to its equity investment at risk.
  - Delmarva has no voting or decision making rights. All such rights are retained by Conectiv Energy. Delmarva has no obligation to absorb losses of the project.

Other factors to consider include:

- The Delmarva RFP is only 10 years out of the asset's projected life of 40 years.
- Conectiv Energy is an ongoing business. It has a large number of other customers and assets. This project would represent only a small amount of its business.

Based on Conectiv Energy's evaluation, Delmarva would not be required to consolidate the project under FIN 46(R).

TABLE OF CONTENTS

TABS	**TITLE**
II.	**BASE BID PROPOSAL – Application Forms**
	p. Form P – Complete with Attachments

Form P - Project Management

Bidders are required to demonstrate project experience and management capability to successfully develop and operate the Facility as proposed. Company is particularly interested in a project team which has demonstrated success in Projects of a similar nature, type, size and technology and can demonstrate an ability to effectively work together and for greenfield projects to bring the Facility to COD.

1) Provide an organizational chart for the Facility that lists the participants and consultants and identifies the management structure and responsibilities.
Response: See Attachment Marked Form P / Item 1 - Facility Organization Chart

2) For each of the participants (i.e., project developer, A/E firm, EPC firm, fuel supplier, environmental staff or consulting firm, legal services, etc.) provide brief experience statements which lists the specific experience of the firm, other projects of similar nature, type, size and technology, and any evidence that the participants have worked jointly on other projects.
Response: See Attachment Marked Form P / Question 2

3) Provide a management chart that lists the key management personnel, title, lines of responsibility and reporting requirements for the Facility project team.
Response: See Attachment Marked Form P / Item 3 Corporate Reporting

4) Provide the resumes of the important project management and key support staff dedicated to the Facility.
Response: See Attachment Marked Form P / Question 4

5) Provide documentation regarding the contractual relationship between the project sponsor and all additional participants or vendors. Indicate the status of any arrangements between the Bidder and vendors.
Response: See Attachment Marked Form P / Question 5

6) Provide a listing of all similar projects the Bidder has successfully developed. Provide the following information as part of the response:

- Name of the project
- Location of the project
- Project type, size and technology
- Purchasing utility
- Schedule and actual commercial operation date
- Whether the unit is dispatchable or must-run
- Capacity factor of the unit for its entire term of operation
- Availability factor of the unit for its entire term of operation
- Sponsor’s role in the project
- Identify any environmental violations

Response: See Attachment Marked Form P / Question 6

7) Provide copies of report material related to safety of operations including reports on reportable injuries, instances of accidents, injuries, or fatalities, lost workday injuries, loss of operations due to safety issues, etc. at facilities currently owned or maintained by the Bidder.

Response: See Attachment Marked Form P / Question 7

Form P - Project Management

8) Describe Bidder's commitment to safety of operations including any operating practices designed to encourage safety commitments (such as bonus programs related to safety performance).

Conectiv Energy is committed to Safety! Safe operation and working practices are part of every activity at each of the sites. All sites include the following mandated activities:

1. Monthly Safety Meetings covering as a minimum, mandatory OSHA topic, critical safety issues at the facilities, best practices, and open forums to address concerns.

2. Tail Gates / Pre-Job conferences – depending on the severity of the job could be anything from a tool box discussion or an expanded multi-craft and multi-departmental meeting to review hazards and implement best working practices.

3. Job Safety Analysis Reviews and Audits – every management employee is required to audit, at a minimum, one job in progress for all elements of safety.

4. Serious Incident Review Committee – All injuries or near misses that result in discipline are reviewed by the committee, not for punitive purposes, but for educational purposes. The findings from each review are published throughout the organization and reviewed at daily tail gates and SAC meetings.

5. Accident Investigations / Communication of events immediately following an injury at any site. Information used at daily tail gates and each department SAC meeting.

6. Milestone Celebrations – each facility has celebrations and issues safety awards for major milestones for annual anniversaries for Lost time and Recordable Injuries.

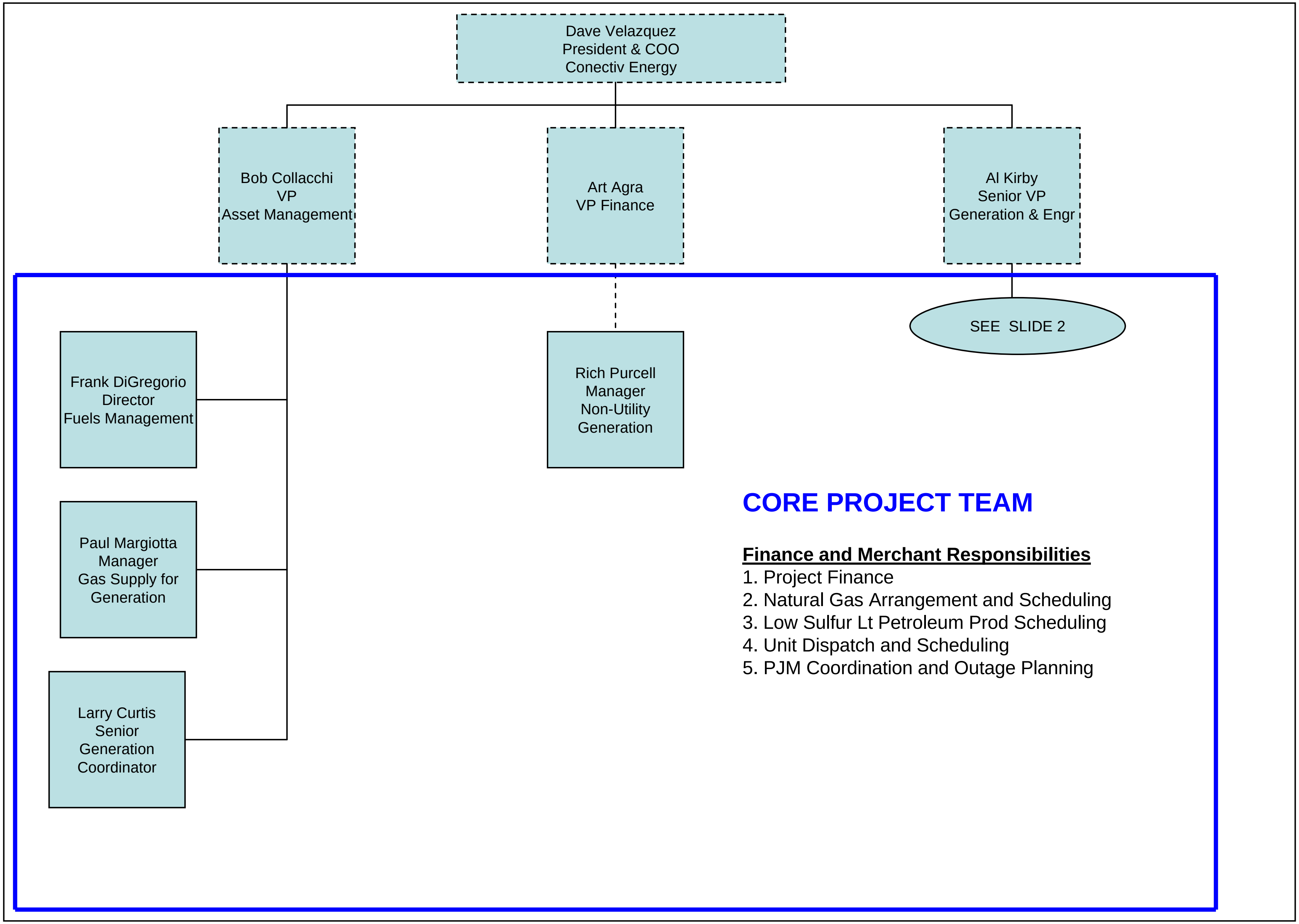
7. All Management Employees have key Safety performance matrices in the individual goals and bonus plans to reinforce the value of safe performance.

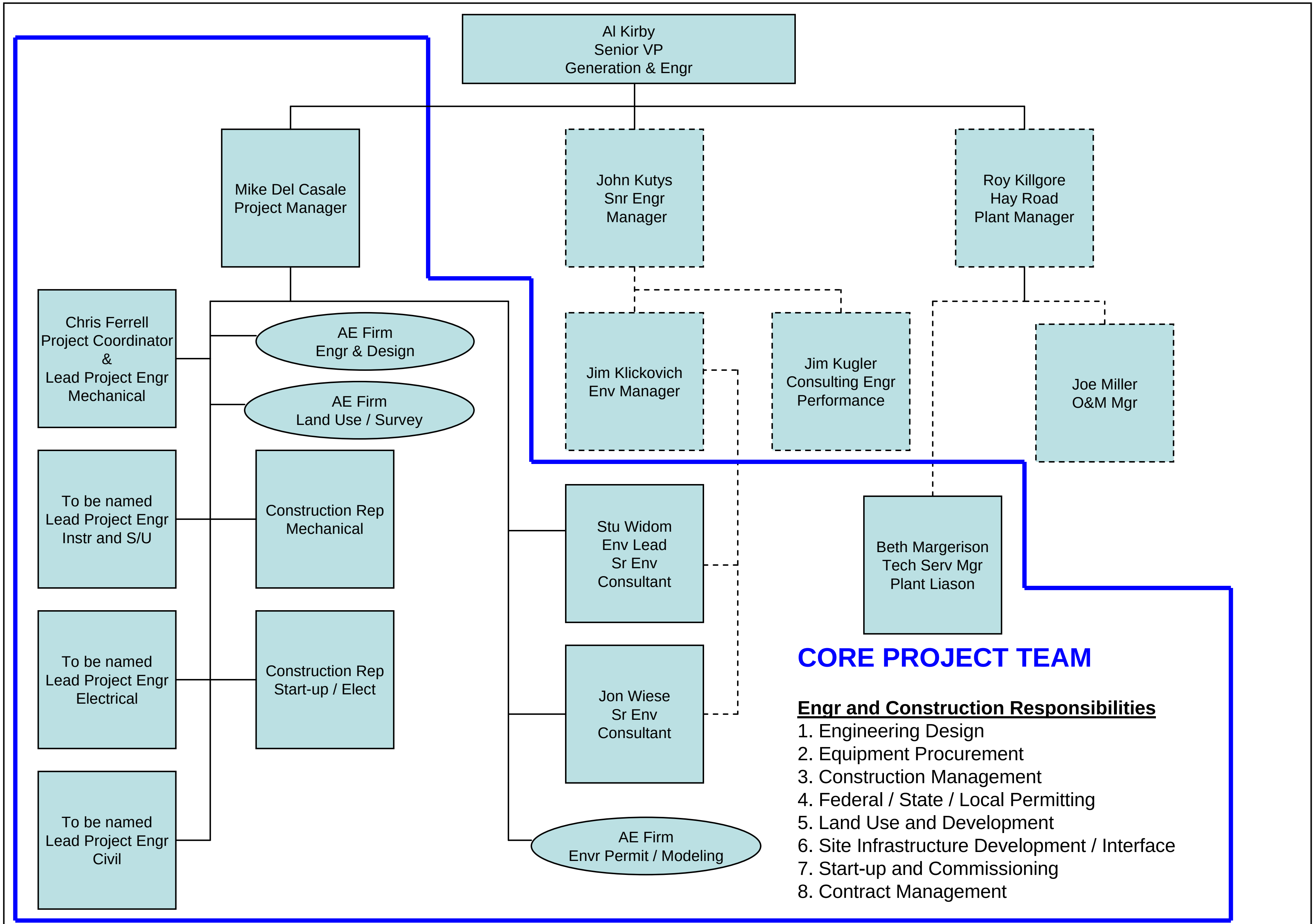
8. All exempt employees have Quarterly bonus plan of up to 0.5% of the base salary, 2% per year, for not experiencing a lost time or recordable injury.

9. OSHA compliant LOTO program at each facility.

10. Safety Statistics are published weekly and monthly in Conectiv Energy Publications for all to adopt lessons learned from each event.

FORM P / ITEM 1- FACILITY ORGANIZATION CHART- FINANCE AND MERCHANT





CORE PROJECT TEAM

<u>Engr and Construction Responsibilities</u>

1. Engineering Design
2. Equipment Procurement
3. Construction Management
4. Federal / State / Local Permitting
5. Land Use and Development
6. Site Infrastructure Development / Interface
7. Start-up and Commissioning
8. Contract Management

FORM P – QUESTION NO. 2

For each of the participants (i.e., project developer, A/E firm, EPC firm, fuel supplier, environmental staff or consulting firm, legal services, etc.) provide brief experience statements which lists the specific experience of the firm, other projects of similar nature, type, size and technology, and any evidence that the participants have worked jointly on other projects.

If Conectiv Energy is the successful bidder, project development, permitting, equipment procurement, construction management, and start-up and commissioning will be executed utilizing in house personnel. Conectiv has proven, after various reviews, that self managed projects result in lower project costs, reduced long term maintenance costs, and improved plant efficiency and reliability. Furthermore, better schedule and project control is maintained.

Once the award is made, Conectiv Energy will enter into commercial relationships with an Architectural Engineering firm and an Environmental firm to perform detailed engineering. Conceptual designs and plant layouts have already been completed in house.

As detailed in Question No. 6 below, Conectiv has recent development experience and has retained a substantial number of the project technical and environmental team members that successfully permitted, installed, and commissioned 1650 MW of capacity and energy in the last five (5) years using the same technology. The contractors and firms who participated in these projects are still viable entities and will be used where cost and schedule permit.

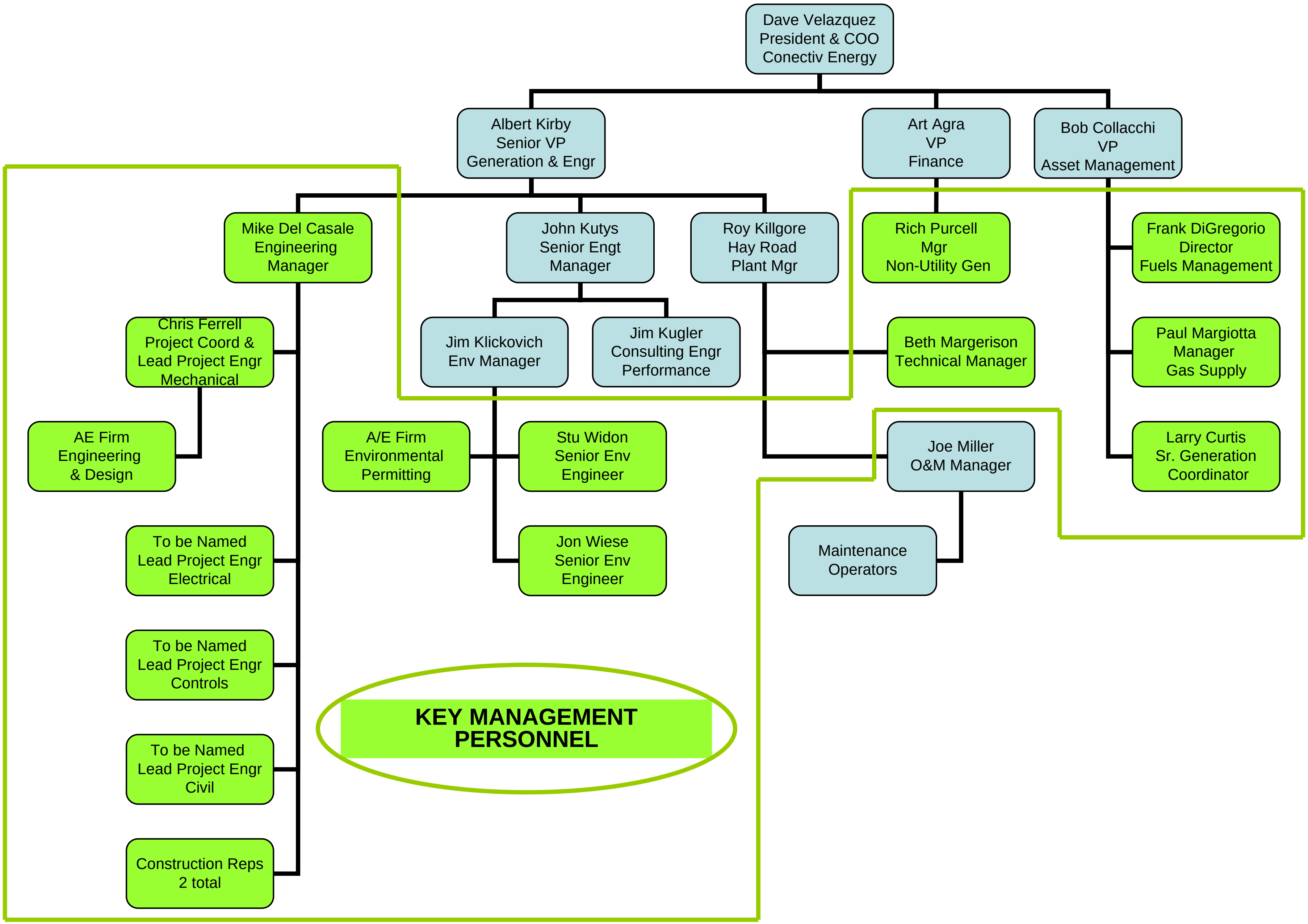
At this time, with project and schedule uncertainties, the actual participants are not known. If successful, the names of all of the prime contractors will be shared at the time of the individual contract award.

Fuel supply to the project will be managed using the Conectiv Energy merchant desk. Conectiv Energy manages and operates a portfolio of more than 3600 MW of generation including base load units, combined cycle / mid-merit load units, and peak load units. This portfolio, which includes more than 2000 MW of dual fuel combined cycle power, has been successfully managed for more than ten (10) years.

For natural gas, the plant will be served by a dedicated gas pipeline that connects to three (3) natural gas pipe line companies; TETCO, Transco, and Columbia Gas. The three pipe lines offer supply sources ranging from Texas to the Gulf of Mexico, US Mid-continent, and the Applalachian supply areas. Conectiv Energy has multiple long standing commercial arrangements with each of these entities to serve this project and the existing 1100 MW installed at the Hay Road Power Complex.

For low sulfur light petroleum products, deliveries to the site will be by barge from either the Baltimore, Philadelphia, or New York markets, as is currently done, and will be stored on site using the existing 10,000,000 gallons of storage.

FORM P / ITEM 3: PROJECT TEAM – CORPORATE REPORTING REQUIREMENT



FORM P – QUESTION NO. 4

Provide the resumes of the important project management and key support staff dedicated to the Facility.

Resumes and detailed work history of key project management and key support staff will be provided, if required, during the final award process.

FORM P – QUESTION NO. 5

Provide documentation regarding the contractual relationship between the project sponsor and all additional participants or vendors. Indicate the status of any arrangements between the Bidder and vendors.

Conectiv Energy intends to develop this project, lead the permitting efforts, specify and procure the equipment, manage construction, and start-up and commission the units using in house staff. Historically Conectiv Energy has been very successful managing projects using this format going back to the late 1980's with the installation of the simple cycle Combustion Turbines at Hay Road, the conversion to Combined Cycle in 1993, the development and commercial operation of Hay Road Units 5 – 8 in 2001 & 2002, Bethlehem Units 1 - 4 in 2002 & 2003, and Bethlehem Units 5 – 8 in 2003.

Contracted efforts will include detailed engineering, permit and air modeling, equipment fabrication and manufacturing, and equipment installation. Upon successful award of this project, contracts will be awarded for the detailed engineering and permitting efforts. With the extended permit processing, equipment procurement and installation contracts will not be released until 2008. Using this strategy, Conectiv Energy is still forecasting Commercial Operation in 2011, years before the required end date.

All of the vendors, suppliers, and contractors planned to be utilized on this project have history with Conectiv Energy through the prior development projects and/or through maintenance activities at the existing generation facilities. Although currently there are limited activities, documentation can be provided upon request for prior commercial relationships. During the project development phases, Conectiv Energy will provide the information as the contract arrangements are consummated.

FORM P- QUESTION 6

Provide a listing of all similar projects the Bidder has successfully developed. Provide the following information as part of the response:

TABLE I - SUMMARY TABLE	PROJECT NO. 1	PROJECT NO. 2	PROJECT NO. 3
NAME OF THE PROJECT	HAY ROAD 5 -8	Bethlehem 1 - 4	Bethlehem 5 - 8
LOCATION OF PROJECT	Wilmington, DE	Bethlehem, PA	Bethlehem, PA
PROJECT TYPE	Combined Cycle	Combined Cycle	Combined Cycle
PROJECT SIZE	550 MW	550 MW	550 MW
PROJECT TECHNOLOGY	E - technology	E-technology	E-technology
PURCHASING UTILITY	Delmarva Power	PPL	PPL
SCHEDULE AND ACTUAL CO DATES	See Table II Below	See Table III Below	See Table IV Below
DISPATCHABLE / MUST RUN	Dispatchable	Dispatchable	Dispatchable
LIFE TIME CAPACITY FACTOR	17.0%	13.9%	11.3%
AVAILABILITY FACTOR	85.7%	90.0%	88.3%
SPONSER'S ROLE IN PROJECT	Owner / Constructor	Owner / Constructor	Owner / Constructor
ENV VIOLATIONS - CONSTRUCTION	None	None	None

TABLE II: HR 5 - 8 SCHED VS. ACTUAL COMMERCIAL OPS DATES

	PROJECT MILESTONES	ACTUAL DECLARED DATE	NOMINAL RATING
CT NO. 5 - SIMPLE CYCLE	01-May-01	01-May-01	120
CT NO. 6 - SIMPLE CYCLE	15-Jun-01	07-Jun-01	120
CT NO. 7 - SIMPLE CYCLE	15-Jul-01	15-Jul-01	120
STG NO 8 / COMBINED CYCLE	01-May-02	01-May-02	185

TABLE III: BETH 1- 4 SCHEDULED VS. ACTUAL COMMERCIAL OPS DATES

	PROJECT MILESTONES	ACTUAL DECLARED DATE	NOMINAL RATING
CT NO. 1 - SIMPLE CYCLE	01-Dec-02	01-Dec-02	120
CT NO. 2 - SIMPLE CYCLE	15-Dec-02	15-Dec-02	120
CT NO. 3 - SIMPLE CYCLE	31-Dec-02	31-Dec-02	120
STG NO 4 / COMBINED CYCLE	01-Jun-03	01-Jun-03	185

TABLE IV: BETH 5 - 8 SCHEDULED VS. ACTUAL COMMERCIAL OPS DATES

	PROJECT MILESTONES	ACTUAL DECLARED DATE	NOMINAL RATING
CT NO. 5 - SIMPLE CYCLE	15-Jan-03	15-Jan-03	120
CT NO. 6 - SIMPLE CYCLE	15-Feb-03	15-Feb-03	120
CT NO. 7 - SIMPLE CYCLE	15-Mar-03	15-Mar-03	120
STG NO 8 / COMBINED CYCLE	15-Dec-03	15-Dec-03	185

FORM P – QUESTION NO. 7

Provide copies of report material related to safety of operations including reports on reportable injuries, instances of accidents, injuries, or fatalities, lost workday injuries, loss of operations due to safety issues, etc. at facilities currently owned or maintained by the Bidder.

The Safety performance summaries for the years 1998 through November 1, 2006 for all units Owned or Operated and Maintained are included in the tables below. Table No. 1 shows the Recordable Injuries and the OSHA rates for each of the referenced years. Table No. 2 shows the types of injuries that were experienced in the last three (3) years.

TABLE NO. 1:

GENERATION / ENERGY SAFETY PERFORMANCE HISTORY 1998 - 2006

RECORDABLE INJURIES

PLANTS	1998	1999	2000	2001	2002	2003	2004	2005	2006
B.L. England	6	5	5	4	5	2	4	4	3
Deepwater	0	1	3	3	2	2	1	1	3
Edge Moor	0	6	2	3	6	2	4	1	0
Hay Road	2	2	0	1	1	0	1	0	1
Comb. Turbines	0	0	1	0	1	1	0	0	1
Delaware City	3	3	12	5	5	4	6	4	2
Bethlehem	n/a	n/a	n/a	n/a	n/a	0	0	2	0
Energy	n/a	n/a	n/a	n/a	n/a	1	0	0	1
Atlantic Thermal	n/a	n/a	n/a	n/a	n/a	2	n/a	n/a	n/a
Other Sites	4	3	8	3	4	2	n/a	n/a	n/a
TOTAL INJURIES	15	20	31*	19	24	16	16	12	11
YEARLY TARGET	26	25	25	22	19	19	17	16	14
OSHA Rec. Rate	1.97	2.47	2.09	2.47	3.04	2.08	2.30	1.76	

TABLE NO. 2:

TYPE OF INJURY / PART OF BODY ANALYSIS

Type of Injury	2004	2005	2006	Part of Body	2004	2005	2006
Strain/Sprain	4	6	4	Back	2	1	1
Caught Between	4	1	1	Leg	6	2	2
Slip/Trip	5	0	1	Arm/Elbow	1	1	3
Bruise/Broken	0	2	2	Shoulder	0	3	0
Fall	0	0	1	Hand/Finger	4	2	3
Foreign Object	1	2	0	Eye	1	2	0
Burn	1	1	0	Lung	0	0	0
Bite	1	0	0	Head	1	0	1
Cut	0	0	2	Other	1	1	1
TOTAL	16	12	11	**TOTAL**	16	12	11

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II.	**BASE BID PROPOSAL – Application Forms**
	q. Form Q – Complete with Attachments

Form Q - O&M Plan

Operations and maintenance (O&M) is an important element of successful Facility operations. Bidders should demonstrate that the Facility's maintenance plan, level of funding and mechanism for funding will ensure reliable operation.

1) Provide a detailed operation and maintenance plan for the Facility that contains the following information:

a. Description of the O&M funding and funding level;
See Attachment Marked Form Q / Question 1 / Sub-Section (a)

b. The basis for selecting the funding mechanism.
See Attachment Marked Form Q / Question 1 / Sub-Section (b)

c. The O&M staffing levels expected for the Facility, including the on-site staffing levels and other resources available during a forced outage;
See Attachment Marked Form Q / Question 1 / Sub-Section (c)

d. The expected role of the Bidder or outside contractors in providing maintenance services;
See Attachment Marked Form Q / Question 1 / Sub-Section (d)

e. Plans for staffing the Facility, including the delegation of environmental compliance responsibilities;
See Attachment Marked Form Q / Question 1 / Sub-Section (e)

f. Detailed plans for maintenance on the major pieces of equipment, including the frequency of preventative maintenance.
See Attachment Marked Form Q / Question 1 / Sub-Section (f)

g. Description of any operational guarantees to be in place at the facility.
See Attachment Marked Form Q / Question 1 / Sub-Section (g)

2) Describe the status of the Bidder in securing any maintenance agreements or contracts. Indicate the preferred provider and if available, provide copies of the agreements or contracts.

The new generation project will be operated and maintained via a separate O&M agreement with the existing Hay Road Site Contractor, Conectiv Delmarva Generation or some other Conectiv Energy entity. No agreements are in place at this time.

3) Indicate the expected annual fixed O&M cost in $/kWyear and annual average non-fuel variable O&M operating costs in $/MWh. This data may be used to support the computer simulation exercise in the Detailed Evaluation.

The Variable O&M (VOM), which excludes fuel & emission costs, is based on a eight hour minimum run time and is $5.15/Mwh and is included in the Energy price. The fixed O&M in Year 1 of the contract term is $4/kw-month and is included in the Capacity price.

1. Provide a detailed operation and maintenance plan for the Facility that contains the following information:

   a. **Description of the O&M funding and funding level;**
   The anticipated O&M funding level is based on historical data base developed for fixed and variable operating and maintenance. Fixed costs will be shared across the additional MW with minimum staff impacts. Variable costs were estimated to be on a Capacity Factor of 48% on an "Equivalent Operating Hour" basis with a fixed multiplier for each start. The total number of start/stops for the facility is estimated to be 250 per year.

   b. **The basis for selecting the funding mechanism**.
   As indicated in Question a, the basis is the historical data base that has been developed for the Hay Road Power complex from replicated equipment.

   c. **The O&M staffing levels expected for the Facility, including the on-site staffing levels and other resources available during a forced outage;**
   The existing Hay Road facility utilizes a 24-hour/7-day rotating operating staff that is responsible for both plant maintenance and operations. This staff consists of four shifts to cover operation of the units and perform routine maintenance, and one utility shift primarily responsible for maintenance activities (duties and work hours rotate between shifts). Final staffing evaluations have not been completed, but with small incremental change in operational requirements, the effects to the existing staff will be minimal.

   During forced outages, depending on the root cause, in house staff will handle all control issues, pump, and other medium range maintenance projects. Larger scale requirements such as Combustion Turbine centerline work will be contracted out using the OEM or other qualified contractors that have worked at the facility. Conectiv Energy has long standing relationships with multiple contractors and all OEM's.

   d. **The expected role of the Bidder or outside contractors in providing maintenance services;**
   The Bidder, CESI, will be purchasing the output of the Project for resale to DPL (however, if its Alternate Option is selected, the Energy from the Project may be sold to another third party). The Project will be owned, operated and maintained by an affiliate of the Bidder, either Conectiv Delmarva Generation, Inc. (the owner of Hay Road 1-8 also referred to as "CDG") or another Conectiv Energy Holding Company subsidiary. Either CDG or the other affiliated owner of the Project will perform routine and preventative maintenance will be performed using the existing plant staff. Annual maintenance and major maintenance will be performed by qualified contractors under competitively bid work packages. Where required, OEM Technical Field Advisors will be required to supplement the plant engineering staff.

e. **Plans for staffing the Facility, including the delegation of environmental compliance responsibilities;**
The current plant staff which includes a Plant Manager, two (2) Functional Managers, Operation, Maintenance and Planning Supervisors, twenty-eight (28) Maintenance Operations, four (4) Instrument Technicians, three (3) engineers, and an Environmental Engineer will be able to operate and maintain the expanded facility. (Additional manning studies are being evaluated but no addition is anticipated at this time). This staff is well experienced and will apply the knowledge and skill to meet all commercial obligations. In addition, supplemental staff and technical expertise is available through Conectiv's central Engineering and Environmental departments

f. **Detailed plans for maintenance on the major pieces of equipment, including the frequency of preventative maintenance.**
Major maintenance will be performed in accordance with recommendations from original equipment manufacturers and the historical profile of the same or similar equipment currently operating at Hay Road. Combustion turbine major overhauls will be performed based on equivalent operating hours (EOH). Major overhauls are scheduled approximately every 30,000 – 33,000 EOH's (generating hours plus an additional 10 hours for every start). Major overhauls on the steam turbine are normally scheduled every 8 to 10 years. Routine maintenance will be performed in accordance with recommendations from original equipment manufacturers and the historical profile of the same or similar equipment.

g. **Description of any operational guarantees to be in place at the facility.**
All new equipment will be contracted to include performance guarantees and warranties for sustained performance. These guarantees will be full enforceable utilizing commercial terms. Final details will be made available as Contracts are awarded.

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II. **BASE BID PROPOSAL – Application Forms**

r. Form R – Complete with Attachments

Form R - PPA Pricing

As indicated in the RFP, bidders are required to provide pricing schedules for capacity and energy (including ancillary services) under the proposed PPA. In addition to pricing schedules, bidders should provide a narrative discussion of the proposed pricing schedule including fixed and variable pricing. If formulaic pricing options are included, DPL request bidders to provide a sample of the calculation including a description of the components.

Separate forms must be submitted for any pricing alternatives, including pricing options tied to a general inflation index, alternate in-service year options, or of the volumetric differences.

Pricing and Volume Schedules

Capacity

- Pricing schedules for capacity should reflect either (a) a levelized fixed payment in $/kWmonth over the life of the contract or (b) a combination of fixed and indexed payments (indices will be subject to the limits set forth in the RFP).
- Pricing schedule should indicate proposed contract volume.
- Volume should be tied to the net summer capacity rating of the generation project; for intermittent renewable energy projects UCAP should be used.

Energy

All pricing must be provided in terms of current year dollars, also referred to as nominal or escalated dollars. Bidders may propose prices that are either fixed for the term, escalate at a known (non-indexed) rate or subject to escalation tied to an index that is clearly and closely related to the item being escalated.

- Provide a discussion the proposed energy pricing schedule including fixed and variable pricing.
- If using indexed pricing, provide the index (e.g. Henry Hub).
- If prices are escalated, provide the escalation basis (e.g. fixed percentage, CPI, PPI, GDP Deflator).
- All indices or escalators relied on in the price proposal must be described in sufficient detail to allow for easy identification of the item. Only indices and escalators available through public sources will be acceptable for purposes of the PPA.
- If using caps or collars, levels should be clearly specified.

Ancillary Services

- Bidders should specify the ancillary services that the Facility is capable of providing and the level of availability for each product and whether compensation is included in the capacity payments or bidder is proposing separate pricing.

Form R - PPA Pricing

Renewable Energy Certificates

- Bidders of renewable projects should specify the RECs that the facility can provide based on tis expected annual output and the RECs proposed to be sold to Delmarva and the associated price.

FORM R - PPA Pricing Schedules

Conectiv Energy is offering DPL two alternative pricing options within this Proposal. The first alternative (the "Base Offer") is a unit contingent sale under which CESI will sell to DPL all of the Products produced at the Project and gives to DPL the right to direct the dispatch of the Project. Pricing for the Base Offer is unique and includes prices for all PJM on-peak hours in the base operating mode of the Project (up to 152 MW) indexed to coal indices and the GDP implicit price deflator. Conectiv Energy believes that this should provide the price stability sought in the RFP. For all PJM off-peak hours and periods and for power dispatched in excess of base operating mode (up to 177 MW), Conectiv Energy will offer alternate pricing structures to provide DPL the option of purchasing power under the PPA only when economically beneficial.

The second alternative (the "Alternate Offer") grants to DPL the capacity associated with the Project (177 MW) and the right to the revenue obtained from PJM for the sale of Ancillary Services associated with the Project. It also permits DPL to dictate its Energy purchases under the PPA as if those purchases were being met by operation of the Project. However, it gives CESI control over the dispatch of the Project and permits CESI to decide upon the source of the Energy delivered to DPL pursuant to the contract requirements. The Alternative Offer is, therefore, an asset backed capacity agreement with firm energy.

The Base Offer

CESI will make available all of the Products (Unforced Capacity, Energy and Ancillary Services - all products as defined by PJM) from the electric power generating facility (HayRoad 9-10 - defined as the net 177 MW - 152 MW Base Mode and 25 MW Peak Segment) located in the State of Delaware. This pricing structure assumes no electrical system upgrades for this project. Any upgrade costs will be factored into the Capacity pricing. The Monthly Price paid by DPL to CESI for all available Products delivered to DPL shall be equal to the sum of the Capacity and the Energy Components as specified in Table 1 below:

Table 1: Capacity and Energy Prices

Contract Year (ending May 31)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capacity [1] ($/kw-month)	21.50	21.50	21.50	21.50	21.50	21.50	21.50	21.50	21.50	21.50
Energy [2] ($/MWH)	$48.00	$49.20	$50.43	$51.69	$52.98	$54.31	$55.67	$57.06	$58.48	$59.95

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1 Capacity Price will be adjusted by using the average 60 month closing price of Henry Hub Natural Gas on NYMEX on the day the contract is executed and receives all required regulatory approvals for contract quantity of 177 MW. The adjusted Capacity Price is calculated as follows:

Adj. Capacity Price = (Capacity Price *2/3) + (Capacity Price *1/3* [1+ (60 Month Average HH NYMEX Closing Price on date after execution and all regulatory approvals are received for the contract - 60 Month Average HH NYMEX Closing Price on Dec 20, 2006)/60 Month Average HH NYMEX Closing Price on Dec 20, 2006]

2 The contract year Energy price delivered to the Delaware portion of the Delmarva Zone in $/MWH is applied to a quantity of energy that is equal to the MWH that would be generated by the project in **Base mode of operation during the on-peak hours with the day ahead dispatch (by 4:30 p.m.)** for a minimum of 8 hours runtime. (On-peak and Off-peak hours are as defined by PJM on December 21, 2006). The adjusted Energy Price is calculated as follows:

Adj. Energy Price = Energy Price * [1+ (60 Month Average HH NYMEX Closing Price on date after execution and all regulatory approvals are received for the contract - 60 Month Average HH NYMEX Closing Price on Dec 20, 2006)/60 Month Average HH NYMEX Closing Price on Dec 20, 2006]. The Energy price, after Contract year 1, is escalated using a Platts OTC Coal Broker-Based "NYMEX look-alike - 12,000 Btu/lb. -1%" index (50%) and GDP Implicit Price deflator (50%)

Energy Price for Off-peak Dispatch or Dispatch initiated after 4:30 p.m. in Base mode:
The energy price for Off-peak Dispatch or for any Dispatch initiated after 4:30 p.m. in Base mode. is applied to a quantity of energy that is equal to the MWH that would be generated by the project for a minimum of 8 hours runtime

Energy Price = Price of Fuel (Natural Gas based on Gas Daily) * Heat Rate (8,100 Btu/kWh) + VOM ($5/MWH)
Example:
If Gas Daily NG price is $6/mmBtu; then Energy price for the Off-Peak dispatch would be ($6/mmBtu * 8,100/1000 mmBtu/MWH) + $5/MWH = $53.60/MWH

Energy Price for Peak Segment Dispatch
The energy price for the Peak Segment dispatch is applied to a quantity of energy that is equal to the MWH that would be generated by the project in Peak mode of operation for a minimum of 4 hours runtime(in either the on-peak or off-peak hours)

Energy Price = Price of Fuel (Natural Gas based on Gas Daily) * Heat Rate (13,000 Btu/kWh) + VOM ($18/MWH)
Example:
If Gas Daily NG price is $6/mmBtu; then Energy price for the Peak Segment would be ($6/mmBtu * 13,000/1000 mmBtu/MWH) + $18/MWH = $96.00/MWH

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III.	**BASE BID EXCEPTIONS AND CLARIFICATIONS**

1. Section 5.2(c) – In the event that, despite making commercially reasonable efforts, Seller fails to obtain (i) permits for the Unit acceptable to Seller and (ii) PJM's permission to interconnect the Unit to the PJM grid then Seller shall have the right to terminate the Agreement and Buyer shall be required to return the entire Development Period Security to Seller within 10 days of such notice of termination. This Section should also provide that Seller shall be deemed to not have permission to interconnect to the PJM grid unless it also adjusts the prices under this Agreement for the costs it incurs for system upgrades associated with such interconnection.

2. Section 5.5 – This Section should be modified to eliminate the one year limitation on delays caused by Force Majeure.

3. Section 6.4 – This Section should be modified to provide Seller with five business days after receipt of notice of the Termination Payment from Buyer to challenge said Termination Payment and to provide for disputes regarding such calculation to be resolved in Dispute Resolution.

4. Section 8.3 – The collateral requirements of 8.1 and 8.2 are adequate to protect Buyer. Therefore, this Section should be modified to permit the Parties to agree that a lien on the Unit may be provided in lieu of the collateral requirements in 8.1 and 8.2. However, the Agreement should not require both the 8.1 and 8.2 collateral requirements and the lien.

5. Section 9.2 – This Section should be modified so that Buyer pays the amount of tax "actually incurred" by Seller rather some calculated amount based upon the average level of emissions in the PJM Classic market.

6. Section 12.1(a)(ii) – This Section should be modified to include a notice requirement and a thirty day opportunity to cure.

7. Section 12.1(a)(iii) – This Section should be modified to include a notice requirement and a thirty day opportunity to cure.

8. Section 12.1(a)(vi) – The Section should be modified so that an event of default does not occur if (i) Seller has initiated a good faith effort to increase the UCAP to the Contract Capacity level and (ii) Seller is providing the difference between UCAP and the Contract Capacity from an alternate source.

9. Section 12.1(a)(vii) – This Section should be deleted because an event of Force Majuere should not operate as an Event of Default triggering Buyer's right to terminate.

10. Section 12.1(a)(x) – This Section should provide for a 10 day cure period.

11. Section 12.1(a)(xi) – This Section should be modified to provide that failure to provide the Project Security Agreement would only constitute a default if the Parties had otherwise agreed that a lien on the Unit was going to be provided in lieu of the collateral requirements of Section 8.1 and 8.2.

12. Section 12.2(c) – This Section should be modified to reflect the fact that Seller's failure to obtain permits shall not be a breach or event of default and should not result in the payment of liquidated damages by Seller to Buyer.

13. All other Sections of the PPA not specifically listed herein which need to be modified to conform to the modifications listed herein should be so conformed.

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	a. Form R
	b. PPA Pricing – Asset Backed PPA

Form R - PPA Pricing

As indicated in the RFP, bidders are required to provide pricing schedules for capacity and energy (including ancillary services) under the proposed PPA. In addition to pricing schedules, bidders should provide a narrative discussion of the proposed pricing schedule including fixed and variable pricing. If formulaic pricing options are included, DPL request bidders to provide a sample of the calculation including a description of the components.

Separate forms must be submitted for any pricing alternatives, including pricing options tied to a general inflation index, alternate in-service year options, or of the volumetric differences.

Pricing and Volume Schedules

Capacity

- Pricing schedules for capacity should reflect either (a) a levelized fixed payment in $/kWmonth over the life of the contract or (b) a combination of fixed and indexed payments (indices will be subject to the limits set forth in the RFP).
- Pricing schedule should indicate proposed contract volume.
- Volume should be tied to the net summer capacity rating of the generation project; for intermittent renewable energy projects UCAP should be used.

Energy

All pricing must be provided in terms of current year dollars, also referred to as nominal or escalated dollars. Bidders may propose prices that are either fixed for the term, escalate at a known (non-indexed) rate or subject to escalation tied to an index that is clearly and closely related to the item being escalated.

- Provide a discussion the proposed energy pricing schedule including fixed and variable pricing.
- If using indexed pricing, provide the index (e.g. Henry Hub).
- If prices are escalated, provide the escalation basis (e.g. fixed percentage, CPI, PPI, GDP Deflator).
- All indices or escalators relied on in the price proposal must be described in sufficient detail to allow for easy identification of the item. Only indices and escalators available through public sources will be acceptable for purposes of the PPA.
- If using caps or collars, levels should be clearly specified.

Ancillary Services

- Bidders should specify the ancillary services that the Facility is capable of providing and the level of availability for each product and whether compensation is included in the capacity payments or bidder is proposing separate pricing.

Form R - PPA Pricing

Renewable Energy Certificates

- Bidders of renewable projects should specify the RECs that the facility can provide based on tis expected annual output and the RECs proposed to be sold to Delmarva and the associated price.

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FORM R - PPA Pricing Schedules (Alternate Offer - Asset backed PPA)

CESI will make available all of the Unforced Capacity, and the revenue from the Ancillary Services from the electric power generating facility (HayRoad 9-10 - defined as the net 177 MW - 152 MW Base Mode and 25 MW Peak Segment) located in the State of Delaware and Energy from any electric power generating facility and delivered to the Delaware portion of the Delmarva Zone. This pricing structure assumes no electrical system upgrades for this project. Any upgrade costs will be factored into the Capacity pricing. The Monthly Price paid by DPL to CESI for all available Products delivered to DPL shall be equal to the sum of the Capacity and the Energy Components as specified in Table 1 below:

Table 1: Capacity and Energy Prices

Contract Year (ending May 31)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capacity [1] ($/kw-month)	16.75	16.75	16.75	16.75	16.75	16.75	16.75	16.75	16.75	16.75
Energy [2] ($/MWH)	$48.00	$49.20	$50.43	$51.69	$52.98	$54.31	$55.67	$57.06	$58.48	$59.95

1 Capacity Price will be adjusted by using the average 60 month closing price of Henry Hub Natural Gas on NYMEX on the day the contract is executed and receives all required regulatory approvals for contract quantity of 177 MW. The adjusted Capacity Price is calculated as follows:

Adj. Capacity Price = (Capacity Price *2/3) + (Capacity Price *1/3* [1+ (60 Month Average HH NYMEX Closing Price on date after execution and all regulatory approvals are received for the contract - 60 Month Average HH NYMEX Closing Price on Dec 20, 2006)/60 Month Average HH NYMEX Closing Price on Dec 20, 2006]

2 The contract year Energy price delivered to the Delaware portion of the Delmarva Zone in $/MWH is applied to a quantity of energy that is equal to the MWH that would be generated by the project in **Base mode of operation during the on-peak hours with the day ahead dispatch (by 4:30 p.m.)** for a minimum of 8 hours runtime. (On-peak and Off-peak hours are as defined by PJM on December 21, 2006). The adjusted Energy Price is calculated as follows:

Adj. Energy Price = Energy Price * [1+ (60 Month Average HH NYMEX Closing Price on date after execution and all regulatory approvals are received for the contract - 60 Month Average HH NYMEX Closing Price on Dec 20, 2006)/60 Month Average HH NYMEX Closing Price on Dec 20, 2006]. The Energy price, after Contract year 1, is escalated using a Platts OTC Coal Broker-Based "NYMEX look-alike - 12,000 Btu/lb. -1%" index (50%) and GDP Implicit Price deflator (50%)

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Energy Price for Off-peak Dispatch or Dispatch initiated after 4:30 p.m. in Base mode:

The energy price for Off-peak Dispatch or for any Dispatch initiated after 4:30 p.m. in Base mode is applied to a quantity of energy that is equal to the MWH that would be generated by the project for a minimum of 8 hours runtime

Energy Price = Price of Fuel (Natural Gas based on Gas Daily) * Heat Rate (8,100 Btu/kWh) + VOM ($5/MWH)
Example:
If Gas Daily is NG price is $6/mmBtu; then Energy price for the Off-Peak dispatch would be ($6/mmBtu * 8,100/1000 mmBtu/MWH) + $5/MWH = $53.60/MWH

Energy Price for Peak Segment Dispatch
The energy price for the Peak Segment dispatch is applied to a quantity of energy that is equal to the MWH that would be generated by the project in Peak mode of operation for a minimum of 4 hours runtime(in either the on-peak or off-peak hours)

Energy Price = Price of Fuel (Natural Gas based on Gas Daily) * Heat Rate (13,000 Btu/kWh) + VOM ($18/MWH)
Example:
If Gas Daily NG price is $6/mmBtu; then Energy price for the Peak Segment would be ($6/mmBtu * 13,000/1000 mmBtu/MWH) + $18/MWH = $96.00/MWH

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V. **ALTERNATE BID EXCEPTIONS AND CLARIFICATIONS**

1. Section 3.1(a) – This Section should be modified to make it clear that Supplier is (i) selling the Contract Capacity to Buyer; (ii) delivering to Buyer any revenues received from PJM for the sale of Ancillary Services associated with the Unit (net of revenues received in compensation for incremental operating costs); and (iii) selling a quantity of Energy to Buyer which such Energy may be produced at the Unit or at another location determined by Seller in its sole discretion. This Section should also describe Buyer's permitted scheduling of its Energy requirements with Seller. Specifically, Buyer shall be permitted to direct Seller to deliver Energy from any source to the Delmarva Zone based on a Base Mode of operation of the Unit (i.e. at 152 MW) or a Peak Mode of operation of the Unit (i.e. 177 MW). Buyer shall also be permitted to schedule deliveries of Energy either on a day-ahead basis or on a real-time basis. All such scheduling shall comply with the operational limitations of the Unit. This Section should include language that requires Seller to obtain FERC approval for sale of the Ancillary Services from the Unit to PJM.

2. Section 3.1(b) – This Section should be modified to make it clear that Buyer has the right to schedule delivery of Energy to the Delmarva Zone but that only Seller has the right to control the scheduled operation of the Unit.

3. Section 3.1(c) – This Section should be modified so that Seller's only commitment with respect to operation of the Unit is that such operation will not impair Buyer's right to the Contract Capacity.

4. Section 3.5(a) – This Section should be modified to make it clear that Seller, rather than Buyer, will schedule the Unit with PJM.

5. Section 3.5(b) – This Section should be modified to make it clear that Seller, rather than Buyer, has the right to schedule the Unit.

6. Sections 3.5(b)(i), (ii), (iii), (iv), and (v) – Because Buyer does not have the right to control the Unit these Sections should be deleted.

7. Section 3.5(c) and (d) – Because Buyer does not have the right to control the Unit these Sections should be deleted.

8. Section 3.9 – This Section should be modified to make it clear that Seller has the right, under all circumstances, to provide Energy required to meet agreement requirements from any source as long as it is delivered to the Delmarva Zone.

9. Section 3.13 – Because Buyer does not have the right to control the Unit this Section should be deleted.

10. Section 3.14 – This Section should be modified to make it clear that Buyer does not have the rights to "all Products" produced at the Unit. Buyer has the right to Contract Capacity and the right to the revenues received by Seller from PJM for the sale of

Ancillary Services. Buyer's right to Energy is limited to its right to the delivery of Energy, from any source to the Delmarva Zone, pursuant to the terms of the Agreement.

11. Section 4.1 – This Section should be deleted since this is a Firm Power Agreement.

12. Section 4.2 – Since this is a Firm Power Agreement the reference to "AA" and the Note at the end of the Section should be deleted.

13. Section 5.2(c) – In the event that, despite making commercially reasonable efforts, Seller fails to obtain (i) permits for the Unit acceptable to Seller and (ii) PJM's permission to interconnect the Unit to the PJM grid then Seller shall have the right to terminate the Agreement and Buyer shall be required to return the entire Development Period Security to Seller within 10 days of such notice of termination. This Section should also provide that Seller shall be deemed to not have permission to interconnect to the PJM grid unless it also adjusts the prices under this Agreement for the costs it incurs for system upgrades associated with such interconnection.

14. Section 5.5 – This Section should be modified to eliminate the one year limitation on delays caused by Force Majeure.

15. Section 6.4 – This Section should be modified to provide Seller with five business days after receipt of notice of the Termination Payment from Buyer to challenge said Termination Payment and to provide for disputes regarding such calculation to be resolved in Dispute Resolution.

16. Section 8.3 – The collateral requirements of 8.1 and 8.2 are adequate to protect Buyer. Therefore, this Section should be modified to permit the Parties to agree that a lien on the Unit may be provided in lieu of the collateral requirements in 8.1 and 8.2. However, the Agreement should not require both the 8.1 and 8.2 collateral requirements and the lien.

17. Section 9.2 – This Section should be modified so that Buyer pays the amount of tax "actually incurred" by Seller rather some calculated amount based upon the average level of emissions in the PJM Classic market.

18. Section 12.1(a)(i) – This Section should be modified so that the reference to "Product" produced at the Unit is replaced by (i) Contract Capacity from the Unit; (ii) revenues received from PJM for the sale of Ancillary Services from the Unit; and (iii) Energy delivered to the Delmarva Zone as required by the Agreement.

19. Section 12.1(a)(ii) – This Section should be modified to include a notice requirement and a thirty day opportunity to cure.

20. Section 12.1(a)(iii) – This Section should be modified to include a notice requirement and a thirty day opportunity to cure.

21. Section 12.1(a)(vi) – The Section should be modified so that an event of default does not occur if (i) Seller has initiated a good faith effort to increase the UCAP to the Contract Capacity level and (ii) Seller is providing the difference between UCAP and the Contract Capacity from an alternate source.

22. Section 12.1(a)(vii) – This Section should be deleted because an event of Force Majuere should not operate as an Event of Default triggering Buyer's right to terminate.

23. Section 12.1(a)(viii) and (ix) – Because this is a Firm Power Agreement these Sections should be deleted.

24. Section 12.1(a)(x) – This Section should provide for a 10 day cure period.

25. Section 12.1(a)(xi) – This Section should be modified to provide that failure to provide the Project Security Agreement would only constitute a default if the Parties had otherwise agreed that a lien on the Unit was going to be provided in lieu of the collateral requirements of Section 8.1 and 8.2.

26. Section 12.2(c) – This Section should be modified to reflect the fact that Seller's failure to obtain permits shall not be a breach or event of default and should not result in the payment of liquidated damages by Seller to Buyer.

27. All other Sections of the PPA not specifically listed herein which need to be modified to conform to the modifications listed herein should be so conformed.